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Friday
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WASHINGTON, DC

[Two Sessions]

WHEN: May 14, 1996 at 9:00 am
May 21, 1996 at 9:00 am

WHERE: Office of the Federal Register Conference Room, 800 North Capitol Street, NW., Washington, DC (3 blocks north of Union Station Metro)

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DEPARTMENT OF AGRICULTURE

Rural Housing and Comunity Development Service

Rural Business and Cooperative Development Service

Rural Utilities Service

Farm Service Agency

7 CFR Parts 1841, 1843, 1845, 1903, 1945, 1980, and 2054

RIN 0560–AE72

Deletion of Obsolete CFR Sections Pertaining to Farm Service Agency (Formerly Farmers Home Administration) Programs

AGENCY: Farm Service Agency, USDA.

ACTION: Final rule.

SUMMARY: This final rule removes, as unnecessary, regulations pertaining to: the Emergency Livestock and Economic Emergency loan programs; the Agricultural Resource Conservation Demonstration Program (ARCDP); the employment, pay, and functions of Farmers Home Administration (FmHA) county or area committees; and voluntary debt adjustment. This action is being taken as part of the National Performance Review program to eliminate excess regulations and to improve the quality of those that remain in effect.

EFFECTIVE DATE: June 3, 1996.

FOR FURTHER INFORMATION CONTACT: Steven R. Bazzell, Senior Loan Officer, Farm Service Agency, United States Department of Agriculture, Farm Credit Programs Loan Making Division, Ag Box Code 0522, Room 5438–S, 14th & Independence Avenue, SW, Washington, DC 20250–0522; Telephone: 202–720–3889; or Facsimile: 202–690–1117; E-mail: sbazzell@WDC.FSA.USDA.GOV.

SUPPLEMENTARY INFORMATION:

Executive Order 12866

The Office of Management and Budget did not review this rule because it was determined to be ''not significant'' for the purposes of Executive Order 12866.

Regulatory Flexibility Act

The Regulatory Flexibility Act is not applicable to this rule since the Farm Service Agency (FSA) is not required by 5 U.S.C. 553, or any other provision of law, to publish a notice of proposed rulemaking to effect these administrative changes.

Environmental Evaluation

This action will not have a significant impact on the quality of the environment. Therefore, neither an Environmental Assessment nor an Environmental Impact Statement is required.

Executive Order 12778

This rule was reviewed in accordance with Executive Order 12778. The provisions of the rule do not preempt State laws, are not retroactive, and do not involve administrative appeals.

Executive Order 12372

For reasons set forth in the Notice to 7 CFR, part 3015, subpart V (48 FR 29115, June 24, 1983), the programs and activities within in this rule are excluded from the scope of Executive Order 12372, which requires intergovernmental consultation with State and local officials.

Paperwork Reduction Act

This final rule does not impose any new information or recordkeeping requirements on the public. The Agency will update the data documenting the burden on the public at its regularly scheduled paperwork burden submissions to OMB.

Background

This final rule removes obsolete regulations concerning former Farmers Home Administration (FmHA) Farmer Programs loans. Under the Department of Agriculture Reorganization Act of 1994 (Pub.L. 103–354) (1944 Act), FmHA programs were transferred to other USDA agencies. FmHA Farmer Programs now are being administered as Farm Credit Programs by the Farm Service Agency (FSA). The Emergency Livestock (EL) program regulations under CFR parts 1841, 1843, 1845 and 1980, subpart C are removed because the Emergency Livestock Credit Act of 1974 (Pub.L. 93–357), as amended, expired on September 30, 1979. The Economic Emergency (EE) program regulations at 7 CFR part 1945, subpart C and part 1980, subpart F are removed because the Emergency Agricultural Credit Adjustment Act of 1978 (Pub.L. 95–334), was repealed by section 1851 of the Food, Agriculture, Conservation and Trade Act of 1990 (Pub. L. 101–624). FSA also is deleting the regulations for administering the Agricultural Resource Conservation Demonstration Program (ARCDP), 7 CFR part 1980 subpart J, because the Department of Agriculture Reorganization Act of 1994 transferred the responsibility for administering the ARCDP from the former FmHA to the Natural Resources Conservation Service, USDA. Regulations concerning the employment, pay, and functions of former FmHA county committees at 7 CFR part 2054, subpart W also will be eliminated because § 227 of the 1994 Act abolished FmHA county committees. FSA is examining the role that the county or area county committees of the former Agricultural Stabilization and Conservation Service, now part of FSA, can play in the agricultural credit area and may promulgate regulations concerning this. Finally, regulations concerning voluntary debt adjustment at 7 CFR part 1903, subpart A, are removed because they are duplicative of comprehensive loan servicing regulations under 7 CFR part 1951.

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7 CFR Part 1841

Agricultural Credit, Loan Guarantees, Loan Liquidation, Loan Servicing, Transfers and Assumptions.

7 CFR Part 1843

Agricultural Credit, Loan Liquidation, Loan Making, Loan Servicing.

7 CFR Part 1845

Agricultural Credit, Emergency Assistance, Guaranteed Loans, Livestock.

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Agricultural Credit, Debt Adjustment, Loan Servicing.

7 CFR Part 1945

Agricultural Credit, Economic Emergency, Emergency Assistance.

7 CFR Part 1980

Agricultural Credit, Agricultural Resource Conservation Demonstration Program.

7 CFR Part 2054

County Committee Function, Elections, Employment.

For the reasons set out in the preamble, CFR Chapter XVIII is amended as follows:

PARTS 1841, 1843, 1845, 1903, AND 2054—[REMOVED]

1. Parts 1841, 1843, 1845, 1903, and 2054 are removed.

PART 1945—[AMENDED]

2. Part 1945 is amended by removing subpart C (§§ 1945.101–1945.150).

PART 1980—[AMENDED]

3. Part 1980 is amended by removing subpart C (§§ 1980.201–1980.294 and Appendix A), subpart F (§§ 1980.501–1980.600 and Appendices A and B), and subpart J (§§ 1980.901 through 1980.1000 and Appendices A through D).

Signed at Washington, D.C. on April 24, 1996.

Eugene Moos,

Under Secretary for Farm and Foreign Agricultural Services.

[FR Doc. 96–11467 Filed 5–9–96; 8:45 am]

BILLING CODE 3410–05–P

DEPARTMENT OF THE TREASURY

Office of the Comptroller of the Currency

12 CFR Part 25

[Docket No. 96–08]

RIN 1557–AB51

FEDERAL RESERVE SYSTEM

12 CFR Part 228

[Regulation BB; Docket No. R–0822]

FEDERAL DEPOSIT INSURANCE CORPORATION

12 CFR Part 345

RIN 3064–AB27

DEPARTMENT OF THE TREASURY

Office of Thrift Supervision

12 CFR Part 563e

[Docket No. 96–32]

RIN 1550–AA96

Community Reinvestment Act Regulations

AGENCIES: Office of the Comptroller of the Currency, Treasury (OCC); Board of Governors of the Federal Reserve System (Board); Federal Deposit Insurance Corporation (FDIC); Office of Thrift Supervision, Treasury (OTS).

ACTION: Joint final rule; correcting amendment.

SUMMARY: The OCC, Board, FDIC, and OTS (collectively, the agencies) are correcting their joint final rule concerning the Community Reinvestment Act (CRA), which was published on May 4, 1995, and amended by a subsequent joint final rule published on December 20, 1995. This document corrects a cross-reference to Small Business Administration regulations, which were recently amended. This correcting amendment makes no substantive change in the requirements of the current regulations.

EFFECTIVE DATE: May 10, 1996.

FOR FURTHER INFORMATION CONTACT:

OCC: Bert A. Otto, Acting Deputy Comptroller for Compliance, (202) 874–5216; or Matthew Roberts, Director, Community and Consumer Law Division, (202) 874–5750, Office of the Comptroller of the Currency, 250 E Street, SW., Washington, DC 20219.

BOARD: Glenn E. Loney, Associate Director, Division of Consumer and Community Affairs, (202) 452–3585; Robert deV. Frierson, Assistant General Counsel, Legal Division, (202) 452–3711; or Leonard N. Chanin, Managing Counsel, Division of Consumer and Community Affairs, (202) 452–3667, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue, NW., Washington, DC 20551.

FDIC: Bobbie Jean Norris, Chief, Fair Lending Section, Division of Compliance and Consumer Affairs, (202) 942–3090; Robert W. Mooney, Fair Lending Specialist, Division of Compliance and Consumer Affairs, (202) 942–3092; or Ann Hume Loikow, Counsel, Regulation and Legislation Section, Legal Division, (202) 898–3796, Federal Deposit Insurance Corporation, 550 17th Street, NW., Washington, DC 20429.

OTS: Timothy R. Burniston, Director, Compliance Policy, (202) 906–5629; Theresa A. Stark, Project Manager, Compliance Policy, (202) 906–7054; or John Flannery, Attorney, Regulations and Legislation Division, Chief Counsel's Office, (202) 906–7293, Office of Thrift Supervision, 1700 G Street, NW., Washington, DC 20552.

SUPPLEMENTARY INFORMATION:

Introduction

The agencies jointly are amending their regulations implementing the CRA (12 U.S.C. 2901 *et seq.*). This joint final rule makes a technical correction to the agencies' joint CRA regulations, 12 CFR parts 25, 228, 345, and 563e. Those regulations establish the framework and criteria by which the agencies assess an institution's record of helping to meet the credit needs of its community, including low- and moderate-income neighborhoods, consistent with safe and sound operations, and provide that the agencies will take those assessments into account in reviewing certain applications.

Background

Last year, the agencies revised their CRA regulations. They adopted a joint final rule, which was published on May 4, 1995 (60 FR 22156). The agencies published a correction and clarification to the joint final rule on December 20, 1995 (60 FR 66048).

Need for Correction to the Final Rule

The agencies' joint final rule, as amended, defines ''community development'' to mean activities that promote economic development by financing businesses or farms that meet the size eligibility standards of 13 CFR 121.802(a) (2) and (3). These size eligibility standards refer to the Small Business Administration's size

limitations for Development Company and Small Business Investment Company (SBIC) programs. *See* 60 FR 22159 (May 4, 1995) and 60 FR 66049 (Dec. 20, 1995).

On January 31, 1996, the Small Business Administration amended its regulations. *See* 61 FR 3280. Effective March 1, 1996, the size limitations for Development Company and SBIC programs are described at 13 CFR 121.301 (b) and (c). 61 FR 3294. Therefore, it is necessary to amend the agencies' CRA regulations to reflect this change.

The agencies are amending their regulations to mention by name the SBA's Development Company and SBIC programs, as well as to refer readers to 13 CFR 121.301. The agencies believe that reference both to the programs by name and to the SBA's regulation by section will more clearly describe the size standards to which the agencies are referring while continuing to direct interested parties to the size standards' general location in the SBA's regulations.

The agencies find that notice and public procedure concerning this correcting amendment are impracticable, unnecessary, and contrary to the public interest under 5 U.S.C. 553(b)(B). The agencies make this finding because these correcting amendments involve only technical corrections to the agencies' CRA regulations and make no substantive changes to the agencies' CRA regulations.

In addition, under 5 U.S.C. 553(d)(3), the agencies have determined to make this correcting amendment effective with less than 30 days prior publication. The agencies find that there is good cause for shortened notice due to the minor nature of the changes. Furthermore, the SBA's amended regulation became effective March 1, 1996 (61 FR 3280), thereby making the current cross-references in the agencies' CRA regulations erroneous as of that date.

Regulatory Flexibility Act

Pursuant to section 605(b) of the Regulatory Flexibility Act, the OCC, Board, FDIC, and OTS hereby certify that this joint final rule will not have a significant economic impact on a substantial number of small entities. The agencies expect that this joint final rule will not have significant secondary or incidental effects on a substantial number of small entities, or create any additional burden on small entities. This joint final rule merely makes a technical correction to a cross-reference in the rules already adopted by the agencies and will not increase burden on institutions. Accordingly, a regulatory flexibility analysis is not required.

Paperwork Reduction Act of 1995

There are no collection of information requirements in this joint final rule.

Executive Order 12866

OCC and OTS: The OCC and the OTS have determined that this joint final rule is not a significant regulatory action as defined in Executive Order 12866.

Unfunded Mandates Reform Act of 1995

OCC and OTS: Section 202 of the Unfunded Mandates Reform Act of 1995, Pub. L. 104–4, 109 Stat. 48 (1995) (Unfunded Mandates Act), requires that covered agencies prepare a budgetary impact statement before promulgating a rule that includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year. If a budgetary impact statement is required, section 205 of the Unfunded Mandates Act also requires covered agencies to identify and consider a reasonable number of regulatory alternatives before promulgating a rule. As discussed in the preamble, this joint final rule amends the agencies' CRA regulations by making one technical correction. Therefore, the OCC and the OTS have determined that this joint final rule will not result in expenditures by State, local, and tribal governments, or by the private sector, of $100 million or more in any one year. Accordingly, the OCC and the OTS have not prepared a budgetary impact statement or specifically addressed the regulatory alternatives considered.

List of Subjects

12 CFR Part 25

Community development, Credit, Investments, National banks, Reporting and recordkeeping requirements.

12 CFR Part 228

Banks, banking, Community development, Credit, Federal Reserve System, Investments, Reporting and recordkeeping requirements.

12 CFR Part 345

Banks, banking, Community development, Credit, Investments, Reporting and recordkeeping requirements.

12 CFR Part 563e

Community development, Credit, Investments, Reporting and recordkeeping requirements, Savings associations.

Office of the Comptroller of the Currency

12 CFR CHAPTER I

For the reasons discussed in the joint preamble, 12 CFR part 25 is amended as follows:

PART 25—[AMENDED]

1. The authority citation for part 25 continues to read as follows:

Authority: 12 U.S.C. 21, 22, 26, 27, 30, 36, 93a, 161, 215, 215a, 481, 1814, 1816, 1828(c), and 2901 through 2907.

§ 25.12 [Amended]

2. In § 25.12(h)(3), the cross reference ''13 CFR 121.802(a)(2) and (3)'' is revised to read ''the Small Business Administration's Development Company or Small Business Investment Company programs (13 CFR 121.301)''.

Dated: April 2, 1996.

Eugene A. Ludwig,

Comptroller of the Currency.

Federal Reserve System

12 CFR CHAPTER II

For the reasons discussed in the joint preamble, 12 CFR part 228 is amended as follows:

PART 228—[AMENDED]

1. The authority citation for part 228 continues to read as follows:

Authority: 12 U.S.C. 321, 325, 1828(c), 1842, 1843, 1844, and 2901 *et seq.*

§ 228.12 [Amended]

2. In § 228.12(h)(3), the cross reference ''13 CFR 121.802(a) (2) and (3)'' is revised to read ''the Small Business Administration's Development Company or Small Business Investment Company programs (13 CFR 121.301)''.

By order of the Board of Governors of the Federal Reserve System, March 20, 1996.

William W. Wiles,

Secretary of the Board.

Federal Deposit Insurance Corporation

12 CFR CHAPTER III

For the reasons discussed in the joint preamble, 12 CFR part 345 is amended as follows:

PART 345—[AMENDED]

1. The authority citation for part 345 continues to read as follows:

Authority: 12 U.S.C. 1814–1817, 1819–1820, 1828, 1831u and 2901–2907, 3103–3104, and 3108(a).

§ 345.12 [Amended]

2. In § 345.12(h)(3), the cross reference ''13 CFR 121.802(a) (2) and (3)'' is revised to read ''the Small Business Administration's Development Company or Small Business Investment Company programs (13 CFR 121.301)''.

By order of the Board of Directors of the Federal Deposit Insurance Corporation.

Dated: April 3, 1996.

Jerry L. Langley,

Executive Secretary.

Office of Thrift Supervision

12 CFR CHAPTER V

For the reasons discussed in the joint preamble, 12 CFR part 563e is amended as follows:

PART 563e—[AMENDED]

1. The authority citation for part 563e continues to read as follows:

Authority: 12 U.S.C. 1462a, 1463, 1464, 1467a, 1814, 1816, 1828(c), and 2901 through 2907.

§ 563e.12 [Amended]

2. In § 563e.12(g)(3), the cross reference ''13 CFR 121.802(a) (2) and (3)'' is revised to read ''the Small Business Administration's Development Company or Small Business Investment Company programs (13 CFR 121.301).''

Dated: April 5, 1996.

By the Office of Thrift Supervision.

Jonathan L. Fiechter,

Acting Director.

[FR Doc. 96–11454 Filed 5–9–96; 8:45 am]

BILLING CODE 4810–33–P, 6210–01–P, 6714–01–P, 6720–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Airspace Docket No. 96–ANM–5]

Establishment of Class E Airspace; Camp Guernsey, Wyoming

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action establishes the Camp Guernsey, Wyoming, Class E airspace to accommodate a new instrument approach procedure at Camp Guernsey Airport, Camp Guernsey, Wyoming. The area will be depicted on aeronautical charts for pilot reference.

EFFECTIVE DATE: 0901 UTC, June 20, 1996.

FOR FURTHER INFORMATION CONTACT: James Riley, ANM–532.2, Federal Aviation Administration, Docket NO. 96–ANM–5, 1601 Lind Avenue S.W., Rentor, Washington, 98055–4056; telephone number: (206) 227–2537.

SUPPLEMENTARY INFORMATION:

History

On February 29, 1996, the FAA proposed to amend part 71 of Federal Aviation Regulations (14 CFR part 71) by establishing the Camp Guernsey, Wyoming, Class E airspace designation (61 FR 7757). Interested parties were invited to participate in the rulemaking proceeding by submitting written comments on the proposal. No comments were received. The coordinates for this airspace docket are based on North American Datum 83. Class E airspace is published in Paragraph 6005 of FAA Order 7400.9C dated August 17, 1995, and effective September 16, 1995, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document will be published subsequently in the Order.

The Rule

This amendment to part 71 of Federal Aviation Regulations establishes Class E airspace at Camp Guernsey, Wyoming. The FAA has determined that his proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, 14 CFR part 71 is amended as follows:

PART 71—[AMENDED]

1. The authority citation for 14 CFR part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389; 14 CFR 11.69.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of the Federal Aviation Administration Order 7400.9C, Airspace Designations and Reporting Points, dated August 17, 1995, and effective September 16, 1995, is amended as follows:

Paragraph 6005 Class E airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

ANM WY E5 Camp Guernsey, WY [New]

Camp Guernsey Airport, WY
(Lat. 42°15′35″ N, long. 104°43′42″ W)

That airspace extending upward from 700 feet above the surface within a 6.7 mile radius of the Camp Guernsey Airport, and within 6.4 miles each side of the 141° bearing from the Camp Guernsey Airport, extending from the 6.7-mile radius to 17.8 miles southeast of the Camp Guernsey Airport.

* * * * *

Issued in Seattle, Washington, on April 18, 1996.

Richard E. Prang,

Acting Assistant Manager, Air Traffic Division, Northwest Mountain Region.

[FR Doc. 96–11729 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–13–M

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14 CFR Part 71

[Airspace Docket No. 96–ANM–002]

Establishment of Class E Airspace; John Day, Oregon

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action established the John Day, Oregon, Class E airspace to accommodate a Global Positioning System (GPS) Standard Instrument Approach Procedure (SIAP) to the John Day State Airport.

EFFECTIVE DATE: 0901 UTC, August 15, 1996.

FOR FURTHER INFORMATION CONTACT: James C. Frala, Operations Branch, ANM–532.4, Federal Aviation Administration, Docket No. 96–ANM–002, 1601 Lind Avenue, SW, Renton, Washington 98055–4056; telephone number: (202) 227–2535.

SUPPLEMENTARY INFORMATION:

History

On March 18, 1996, the FAA proposed to amend part 71 of the Federal Aviation Regulations (14 CFR part 71) to establish Class E airspace at John Day, Oregon, to accommodate a new GPS SIAP to the John Day State Airport (61 FR 10910). Interested parties

were invited to participate in the rulemaking proceeding by submitting written comments on the proposal. No comments were received.

The coordinates for this airspace docket are based on North American Datum 83. Class E airspace areas extending upward from 700 feet or more above the surface of the earth are published in paragraph 6005 of FAA Order 7400.9C dated August 17, 1995, and effective September 16, 1995, which is incorporated by reference in 14 CFR 71.1. The Class E airspace listed in this document will be published subsequently in the Order.

The Rule

This amendment to part 71 of Federal Aviation Regulations establishes Class E airspace at John Day, Oregon. The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the FAA amends 14 CFR part 71 as follows:

PART 71—[AMENDED]

1. The authority citation for 14 CFR part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389; 14 CFR 11.69.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of the Federal Aviation Administration Order 7400.9C, Airspace Designations and Reporting Points, dated August 17, 1995, and effective September 16, 1995, is amended as follows:

Paragraph 6005 Class E airspace areas extending upward from 700 feet or more above the surface of the earth.

ANM–OR E5 John Day, OR

John Day State Airport, OR
(Lat 44°24′14″N, long. 118°57′49″W)

That airspace extending upward from 700 feet above the surface within a 6.5-mile radius of the John Day State Airport; that airspace extending upward from 1,200 feet above the surface within a 9-mile radius of the John Day State Airport, and that airspace within 4 miles either side of a line bearing 076° true from the John Day State Airport, extending from the 9-mile radius to a point 38 miles northeast of the airport, and within an area bounded on the northwest by V357, on the northeast by V4, on the southeast of V269, and on the southwest by V500; excluding that airspace within Federal Airways.

* * * * *

Issued in Seattle, Washington, on May 1, 1996.

Richard E. Prang,

Acting Assistant Manager, Air Traffic Division, Northwest Mountain Region.

[FR Doc. 96–11728 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–13–M

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14 CFR Part 71

[Airspace Docket No. 95–AWP–13]

Establishment of Class E Airspace; Hollister, CA

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action establishes a Class E airspace area at Hollister, CA. The development of a Global Positioning System (GPS) Standard Instrument Approach Procedure (SIAP) to Runway (RWY) 31 has made this action necessary. The intended effect of this action is to provide adequate controlled airspace for Instrument Flight Rules (IFR) operations at Hollister Municipal Airport, Hollister, CA.

EFFECTIVE DATE: 0901 UTC August 15, 1996.

FOR FURTHER INFORMATION CONTACT: William Buck, Airspace Specialist, Operations Branch, AWP–530, Air Traffic Division, Western-Pacific Region, Federal Aviation Administration, 15000 Aviation Boulevard, Lawndale, California, 90261, telephone (310) 725–6556.

SUPPLEMENTARY INFORMATION:

History

On January 8, 1996, the FAA proposed to amend part 71 of the Federal Aviation Regulations (14 CFR part 71) by establishing a Class E airspace area at Hollister, CA (61 FR 549). On March 11, 1996, the FAA issued a supplemental notice to amend this proposal to establish a Class E airspace area at Hollister, (61 FR 9655). This action will provide adequate controlled airspace to accommodate a GPS SIAP to RWY 31 at Hollister Municipal Airport, Hollister, CA.

Interested parties were invited to participate in this rulemaking proceeding by submitting written comments on the proposals to the FAA. No comments to the proposals were received. Class E airspace designations are published in paragraph 6005 of FAA Order 7400.9C dated August 17, 1995, and effective September 16, 1995, which is incorporated by reference in 14 CFR 71.1. The E airspace designation listed in this document will be published subsequently in this Order.

The Rule

This amendment to part 71 of the Federal Aviation Regulations (14 CFR part 71) establishes a Class E airspace area at Hollister, CA. The development of a GPS SIAP to RWY 31 has made this action necessary. The intended effect of this action is to provide adequate controlled airspace for aircraft executing the GPS RWY 31 SIAP at Hollister Municipal Airport, Hollister, CA.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. Therefore, this regulation—(1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 10034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—[AMENDED]

1. The authority citation for 14 CFR part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389; 14 CFR 11.69.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of the Federal Aviation Administration Order 7400.9C, Airspace Designations and Reporting Points, dated August 17, 1995, and effective September 16, 1995, is amended as follows:

Paragraph 6005 Class E airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

AWP CA E5 Hollister, CA [New]

Hollister Municipal Airport, CA
(Lat. 36°53′36″N, long. 121°24′37″W)

That airspace extending upward from 700 feet above the surface within a 4.2-mile radius of the Hollister Municipal Airport and within 2 miles each side of the 142° bearing from the Hollister Municipal Airport, extending from the 4.2-mile radius to 10 miles southeast of the Hollister Municipal Airport and within 2 miles each side of the 320° bearing from the Hollister Municipal Airport extending from the 4.2-mile radius to 5.4 miles northwest of the Hollister Municipal Airport.

* * * * *

Issued in Los Angeles, California, on April 23, 1996.

Harvey R. Riebel,

Acting Manager, Air Traffic Division, Western-Pacific Region.

[FR Doc. 96–11727 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[TD 8669]

RIN 1545–AR18

Computation of Combined Taxable Income Under The Profit Split Method When the Possession Product is a Component Product or an End-Product Form for Purposes of the Possessions Credit Under Section 936

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Final regulations.

SUMMARY: This document contains final regulations relating to the computation of combined taxable income under the profit split method. These regulations amend the current regulations and provide revised rules for taxpayers to compute combined taxable income under the profit split method when the possession product chosen for purposes of section 936(h)(5) of the Internal Revenue Code is a component product or an end-product form. These regulations are necessary to provide guidance to taxpayers electing the profit split method of computing taxable income under section 936(h)(5).

DATES: These regulations are effective May 10, 1996. See Supplementary Information for applicability dates.

FOR FURTHER INFORMATION CONTACT: Jacob Feldman, 202–622–3870 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

Background

On January 12, 1994, the IRS published a notice of proposed rulemaking in the Federal Register (INTL–0068–92, 59 FR 1690, 1994–1 C.B. 820) relating to the computation of combined taxable income under the profit split method under section 936(h)(5) (relating to the possessions credit for U.S. companies doing qualified business in Puerto Rico and certain U.S. possessions). A number of written public comments were received concerning the proposed regulations and a public hearing was held on July 11, 1994. After consideration of all the comments, the proposed regulations are adopted as revised by this Treasury decision. The revisions are discussed below.

Discussion

The proposed regulations would amend § 1.936–6(b)(1), Q&A 12. Under the proposed regulations, combined taxable income for a taxpayer that elects the profit split method for a possession product that is either a component product or an end-product form would be determined by multiplying the combined taxable income of the integrated product that includes the possession product by a production cost ratio. In the case of a component product, the combined taxable income of the integrated product would be multiplied by a ratio the numerator of which is the production costs of the component product and the denominator of which is the production costs of the integrated product. The combined taxable income of an end-product form would be determined in a similar manner using the production costs of the end-product form. The regulations were proposed to be effective for taxable years beginning after 1993.

Taxpayers have argued that the regulations should not be adopted as proposed because they would violate the arm's length standard under section 482 and that a necessary consequence of the abandonment of the arm's length standard would be distortions in taxpayers' income. That is, income would be computed inconsistently for related versus unrelated party sales of the same product, under the same terms and in the same market.

The proposed regulations did not apply the arm's length standard to component products and end-product forms under the profit-split method because application of section 482 in this context is inconsistent with the statutory framework. The effect of the profit split method when applied to possession products is to minimize disputes between taxpayers and the IRS because, unlike section 482 methods, there is no need to perform functional analyses to allocate income among the parties. Because Congress eliminated the section 482 analysis from the profit split method, the proposed regulations did not reinject this analysis into the area of intermediate products.

In response to taxpayer comments, however, the IRS and Treasury are providing an election to taxpayers that sell the same possession product in both component form and integrated form if the transactions meet certain section 482 standards. This method is both simple to apply and produces consistent results with respect to related and unrelated party transactions. Under this method, the combined taxable income from covered sales of the component product shall be determined by using the same per unit combined taxable income as is derived from uncontrolled sales of the product as an integrated product. Taxpayers may elect to compute the combined taxable income for an end-product form in a similar manner if all excluded components are manufactured by a member of the affiliated group that includes the possession corporation and also sold by the group separately in uncontrolled transactions. In that case, the combined taxable income of the end-product form will be computed by reducing the combined taxable income of the integrated product that includes the end-product form by the combined taxable income of the excluded components determined under the rules of section 936 as if the excluded components were possession products. In order to make the election, the uncontrolled sales must meet the comparability standards of the fourth sentence of § 1.482–3(b)(2)(ii)(A), which requires that the uncontrolled and controlled transactions have no differences or minor differences for which adjustment can be made. However, under a no loss limitation, in no case can the taxpayer use as its per

unit combined taxable income for a component product or an end-product form an amount that exceeds the per unit combined taxable income of the integrated product that includes the component product or end-product form.

In 1993, Congress adopted limitations on the amount of the section 936 credit; the taxpayer may be subject to an activity based limitation or may elect a percentage limitation. The election for the percentage limitation had to be made for the first taxable year beginning after December 31, 1993. Taxpayers commented that the proposed regulations created uncertainty with respect to the consequences of making the percentage limitation election and, therefore, the period for making the election should be extended until after the regulations are finalized. This comment is adopted. Taxpayers that have not elected the percentage limitation under section 936(a)(1) for the first taxable year beginning after December 31, 1993, may so elect if the taxpayer has elected the profit split method and the computation of combined taxable income is affected by § 1.936–6(b)(1) Q&A 12.

With respect to the proposed effective date, taxpayers commented that the regulations should not be applied retroactively. One of the justifications for the proposed rule was that it would simplify the computation of combined taxable income and applying the regulation retroactively would not simplify the computation because it would require filing amended returns. This comment is adopted in part. The regulation is effective for taxable years ending 30 days after May 10, 1996. If however, the election under paragraph (v) of A. 12 of § 1.936–6(b)(1) is made, this election must be made for the taxpayer's first taxable year beginning after December 31, 1993, and if not made effective for that year, the election cannot be made for any later taxable year.

The last sentence of paragraph (vi) of A. 13 of § 1.936–6(b)(1) in the proposed regulations provided that, for purposes of determining the estimated tax liability of an affiliate of the possessions corporation with respect to income allocated to it from the possessions corporation, the income would be deemed received on the last day of the taxable year of each such affiliate in which or with which the taxable year of the possessions corporation ended. This rule is limited to taxable years beginning prior to January 1, 1995. For taxable years beginning after December 31, 1994, quarterly estimated tax payments will be required as provided under section 711 of the Uruguay Round Agreements, Public Law 103–465 (1994), page 230, and any administrative guidance issued by the IRS thereunder. See Rev. Proc. 95–23 (1995–1 C.B. 693).

Accordingly, the proposed regulations are finalized as proposed except with respect to the changes discussed above and the necessary conforming changes.

Special Analyses

It has been determined that this Treasury decision is not a significant regulatory action as defined in EO 12866. Therefore, a regulatory assessment is not required. It has also been determined that this regulation does not have a significant impact on a substantial number of small entities. Thus, the Regulatory Flexibility Act (5 U.S.C. chapter 6) does not apply to these regulations, and therefore, a Regulatory Flexibility Analysis is not required. Pursuant to section 7805(f) of the Internal Revenue Code, the notice of proposed rulemaking preceding these regulations was submitted to the Small Business Administration for comment on its impact on small business.

Drafting Information

The principal authors of these regulations are Jacob Feldman and Mary Gillmarten of the Office of Associate Chief Counsel (International), IRS. Other personnel from the IRS and Treasury Department participated in their development.

List of Subjects in 26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

Adoption of Amendments to the Regulations

Accordingly, 26 CFR part 1 is amended as follows:

PART 1—INCOME TAXES

Paragraph 1. The authority citation for part 1 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

Par. 2. In § 1.936–6, paragraph (b)(1) is amended by:

1. Revising *Q. 10.*
2. Amending *A. 10* by:
a. Redesignating the text of *A. 10* as paragraph *A. 10*(i).
b. Removing the last two sentences of newly designated *A. 10*(i).
c. Adding paragraphs *A. 10* (ii) through (v).
3. Revising the first sentence of *A. 11.*
4. Revising *Q&A. 12.*
5. Revising *A. 13.*

The revisions and addition read as follows:

§ 1.936–6 Intangible property income when an election out is made; cost sharing and profit split options; covered intangibles.

* * * * *

(b) * * *

(1) * * *

Q. 10: If the possessions corporation is entitled to use the profit split method in the situation described in *Q. 9* (leasing units of the possession product or use of such units in the taxpayer's own trade or business), how should it compute combined taxable income with respect to such units?

A. 10: (i) * * *

(ii) If the possession product is a component product or an end-product form, the combined taxable income with respect to the possession product shall be determined under *Q&A. 12* of this paragraph (b)(1).

(iii) For purposes of determining the basis of a component product or an end-product form, the deemed sales price of such product must be determined. The deemed sales price of the component product shall be determined by multiplying the deemed sales price of the integrated product that includes the component product by a ratio, the numerator of which is the production costs of the component product and the denominator of which is the production costs of the integrated product that includes the component product. The deemed sales price of an end-product form shall be determined by multiplying the deemed sales price of the integrated product that includes the end-product form by a ratio, the numerator of which is the production costs of the end-product form and the denominator of which is the production costs of the integrated product that includes the end-product form. For the definition of production costs, see *Q&A. 12* of this paragraph (b)(1).

(iv)(A) If combined taxable income is determined under paragraph (v) of *A. 12* of this paragraph (b)(1), in the case of a component product, the deemed sales price shall be determined by using the actual sales price of that product when sold as an integrated product (as adjusted under the rules of the fourth sentence of § 1.482–3(b)(2)(ii)(A)).

(B) If combined taxable income is determined under paragraph (v) of *A. 12* of this paragraph (b)(1), in the case of an end-product form, the deemed sales price shall be determined by subtracting from the deemed sales price of the integrated product that includes the end-product form (e.g., the leased property) the actual sales price of the excluded component when sold as an

integrated product to an unrelated person (as adjusted under the rules of the fourth sentence of § 1.482–3(b)(2)(ii)(A)).

(v) The full amount of income received under the lease shall be treated as income of (and be taxed to) the U.S. affiliate and not the possessions corporation.

* * * * *

A. 11: The U.S. affiliate shall be treated, for purposes of computing its basis in such units, as if it had repurchased such units immediately following the deemed sale and at the deemed sales price as provided in *Q&A. 10* of this paragraph (b)(1). * * *

Q. 12: If the possession product is a component product or an end-product form, how is the combined taxable income for such product to be determined?

A. 12: (i) Except as provided in paragraph (v) of this *A. 12*, combined taxable income for a component product or an end-product form is computed under the production cost ratio (PCR) method.

(ii) Under the PCR method, the combined taxable income for a component product will be the same proportion of the combined taxable income for the integrated product that includes the component product that the production costs attributable to the component product bear to the total production costs (including costs incurred by the U.S. affiliates) for the integrated product that includes the component product. Production costs will be the sum of the direct and indirect production costs as defined under § 1.936–5(b)(4) except that the costs will not include any costs of materials. If the possession product is a component product that is transformed into an integrated product in whole or in part by a contract manufacturer outside of the possession, within the meaning of § 1.936–5(c), the denominator of the PCR shall be computed by including the same amount paid to the contract manufacturer, less the costs of materials of the contract manufacturer, as is taken into account for purposes of the significant business presence test under § 1.936–5(c) *Q&A. 5.*

(iii) Under the PCR method the combined taxable income for an end-product form will be the same proportion of the combined taxable income for the integrated product that includes the end-product form that the production costs attributable to the end-product form bear to the total production costs (including costs incurred by the U.S. affiliates) for the integrated product that includes the end-product form. Production costs will be the sum of the direct and indirect production costs as defined under § 1.936–5(b)(4) except that the costs will not include any costs of materials. If the possession product is an end-product form and an excluded component is contract manufactured outside of the possession, within the meaning of § 1.936–5(c), the denominator shall be computed by including the same amount paid to the contract manufacturer, less cost of materials of the contract manufacturer, as is also taken into account for purposes of the significant business presence test under § 1.936–5(c) *Q&A. 5.*

(iv) This paragraph (iv) of *A. 12* illustrates the computation of combined taxable income for a component product or end-product form under the PCR method. S, a possessions corporation, is engaged in the manufacture of microprocessors. S obtains a component from a U.S. affiliate, O. S sells its production to another U.S. affiliate, P, which incorporates the microprocessors into central processing units (CPUs). P transfers the CPUs to a U.S. affiliate, Q, which incorporates the CPUs into computers for sale to unrelated persons. S chooses to define the possession product as the CPUs. The combined taxable income for the sale of the possession product on the basis of the given production, sales, and cost data is computed as follows:

Production costs (excluding costs of materials):	
1. O's costs for the component	100
2. S's costs for the microprocessors	500
3. P's costs for the CPU's (the possession product)	200
4. Q's costs for the computers	400
5. Total production costs for the computer (Add lines 1 through 4)	1,200
6. Combined production costs for the CPU (the possession product) (Add lines 1 through 3)	800
7. Ratio of production costs for the CPUs (the possession product) to the production costs for the computer	0.667
Determination of combined taxable income for computers:	
Sales:	
8. Total possession sales of computers to unrelated customers and foreign affiliates	7,500
Total costs of O, S, P, and Q incurred in production of a computer:	
9. Production costs (enter from line 5)	1,200
10. Material costs	100
11. Total costs (line 9 plus line 10)	1,300
12. Combined gross income from sale of computers (line 8 minus line 11)	6,200
Expenses of the affiliated group (other than foreign affiliates) allocable and apportionable to the computers or any component thereof under the rules of §§ 1.861–8 through 1.861–14T and 1.936–6 (b)(1), Q&A. 1:	
13. Expenses (other than research expenses)	980
Research expenses of the affiliated group allocable and apportionable to the computers:	
14. Total sales in the 3-digit SIC Code	12,500
15. Possession sales of the computers (enter from line 8)	7,500
16. Cost sharing fraction (divide line 15 by line 14)	0.6
17. Research expenses incurred by the affiliated group in 3-digit SIC Code multiplied by 120 percent	700
18. Cost sharing amount (multiply line 16 by line 17)	420
19. Research of the affiliated group (other than foreign affiliates) allocable and apportionable under §§ 1.861–17 and 1.861–14T(e)(2) to the computers	300
20. Enter the greater of line 18 or line 19	420
Computation of combined taxable income of the computer and the CPU:	
21. Combined taxable income attributable to the computer (line 12 minus line 13 and line 20)	4,800
22. Combined taxable income attributable to CPUs (multiply line 21 by line 7) (production cost ratio)	3,200
23. Share of combined taxable income apportioned to S (50 percent of line 22)	1,600
Share of combined taxable income apportioned to U.S. affiliate(s) of S:	
24. Adjustments for research expenses (line 18 minus line 19 multiplied by line 7)	80
25. Adjusted combined taxable income (line 22 plus line 24)	3,280
26. Share of combined taxable income apportioned to affiliates of S (line 25 minus line 23)	1,680

(v)(A) If a possession product is sold by a taxpayer or its affiliate to unrelated persons in covered sales both as an integrated product and as a component product and the conditions of paragraph (v)(C) of this *A. 12* are satisfied, the taxpayer may elect to determine the combined taxable income derived from covered sales of the component product under this paragraph (v). In that case, the combined taxable income derived from covered sales of the component product shall be determined by using the same per unit combined taxable income as is derived from covered sales of the product as an integrated product, but subject to the limitation of paragraph (v)(D) of this *A. 12*.

(B) In the case of a possession product that is an end-product form, if all of the excluded components are also separately sold by the taxpayer or its affiliate to unrelated persons in uncontrolled transactions and the conditions of paragraph (v)(C) of this *A. 12* are satisfied, the taxpayer may elect to determine the combined taxable income of such end-product form under this paragraph (v). In that case, the combined taxable income derived from covered sales of the end-product form shall be determined by reducing the per unit combined taxable income from the integrated product that includes the end-product form by the per unit combined taxable income for excluded components determined under the rules of this paragraph (v), but subject to the limitation of paragraph (v)(D) of this *A. 12*. For this purpose, combined taxable income of the excluded components must be determined under section 936 as if the excluded components were possession products.

(C) In the case of component products, this paragraph (v) applies only if the sales price of the possession product sold in covered sales as an integrated product (i.e., in uncontrolled transactions) would be the most direct and reliable measure of an arm's length price within the meaning of the fourth sentence of § 1.482–3(b)(2)(ii)(A) for the component product. For purposes of applying the fourth sentence of § 1.482–3(b)(2)(ii)(A), the sale of the integrated product that includes the component product is treated as being immediately preceded by a sale of the component (i.e. without further processing) in a controlled transaction. In the case of end-product forms, this paragraph (v) applies only if the sales price of excluded components separately sold in uncontrolled transactions would be the most direct and reliable measure of an arm's length price within the meaning of the fourth sentence of § 1.482–3(b)(2)(ii)(A) for all excluded components of an integrated product that includes an end-product form. For purposes of applying the fourth sentence of § 1.482–3(b)(2)(ii)(A), the sale of the integrated product that includes excluded components is treated as being immediately preceded by a sale of the excluded components (i.e. without further processing) in a controlled transaction. Under the fourth sentence of § 1.482–3(b)(2)(ii)(A), the uncontrolled transactions referred to in this paragraph (v)(C) must have no differences with the controlled transactions that would affect price, or have only minor differences that have a definite and reasonably ascertainable effect on price and for which appropriate adjustments are made (resulting in appropriate adjustments to the computation of combined taxable income). If such adjustments cannot be made, or if there are more than minor differences between the controlled and uncontrolled transactions, the method provided by this paragraph (v)(C) cannot be used. Thus, for example, these uncontrolled transactions must involve substantially identical property in the same or a substantially identical geographic market, and must be substantially identical to the controlled transaction in terms of their volumes, contractual terms, and market level. See § 1.482–3(b)(2)(ii)(B).

(D) In no case can the per unit combined taxable income as determined under paragraph (v)(A) or (B) of this *A. 12* be greater than the per unit combined taxable income of the integrated product that includes the component product or end-product form.

(E) The provisions of this paragraph (v) are illustrated by the following example. Taxpayer manufactures product A in a U.S. possession. Some portion of product A is sold to unrelated persons as an integrated product and the remainder is sold to related persons for transformation into product AB. The combined taxable income of integrated product A is $400 per unit and the combined taxable income of product AB is $300 per unit. The production cost ratio with respect to product A when sold as a component of product AB, is 2/3. Unless the taxpayer elects and satisfies the conditions of this paragraph (v), the combined taxable income with respect to A will be $200 per unit (combined taxable income for AB of $300 × the production cost ratio of 2/3). If, however, the comparability standards of paragraph (v)(C) of this *A. 12* are met, the taxpayer may elect to determine combined taxable income of product A when sold as a component of product AB using the same per unit combined taxable income as product A when sold as an integrated product. However, the per unit combined taxable income from sales of product A as a component product may not exceed the per unit combined taxable income on the sale of product AB. Therefore, the combined taxable income of component product A may not exceed $300 per unit.

(vi) Taxpayers that have not elected the percentage limitation under section 936(a)(1) for the first taxable year beginning after December 31, 1993, may do so if the taxpayer has elected the profit split method and computation of combined taxable income is affected by *Q&A.12* of this paragraph (b)(1).

(vii) The rules of *Q&A. 12* of this paragraph (b)(1) apply for taxable years ending 30 days after May 10, 1996. If, however, the election under paragraph (v) of *A. 12* of § 1.936–6(b)(1) is made, this election must be made for the taxpayer's first taxable year beginning after December 31, 1993, and if not made effective for that year, the election cannot be made for any later taxable year. A successor corporation that makes the same or substantially similar products as its predecessor corporation cannot make an election under paragraph (v) of A.12 of § 1.936–6(b)(1) unless the election was made by its predecessor corporation for its first taxable year beginning after December 31, 1993.

* * * * *

A. 13: (i) The income shall be allocated to affiliates in the following order, but no allocations will be made to affiliates described in a later category if there are any affiliates in a prior category—

(A) First, to U.S. affiliates (other than tax exempt affiliates) within the group (as determined under section 482) that derive income with respect to the product produced in whole or in part in the possession;

(B) Second, to U.S. affiliates (other than tax exempt affiliates) that derive income from the active conduct of a trade or business in the same product area as the possession product;

(C) Third, to other U.S. affiliates (other than tax-exempt affiliates);

(D) Fourth, to foreign affiliates that derive income from the active conduct of a U.S. trade or business in the same product area as the possession product (or, if the foreign members are resident in a country with which the U.S. has an income tax convention, then to those foreign members that have a permanent establishment in the United States that derives income in the same product area as the possession product); and

(E) Fifth, to all other affiliates.

(ii) The allocations made under paragraph (i)(A) of this *A. 13* shall be

made on the basis of the relative gross income derived by each such affiliate with respect to the product produced in whole or in part in the possession. For this purpose, gross income must be determined consistently for each affiliate and consistently from year to year.

(iii) The allocations made under paragraphs (i)(B) and (i)(D) of this *A. 13* shall be made on the basis of the relative gross income derived by each such affiliate from the active conduct of the trade or business in the same product area.

(iv) The allocations made under paragraphs (i)(C) and (i)(E) of this *A. 13* shall be made on the basis of the relative total gross income of each such affiliate before allocating income under this section.

(v) Income allocated to affiliates shall be treated as U.S. source and section 863(b) does not apply for this purpose.

(vi) For purposes of determining an affiliate's estimated tax liability for income thus allocated for taxable years beginning prior to January 1, 1995, the income shall be deemed to be received on the last day of the taxable year of each such affiliate in which or with which the taxable year of the possessions corporation ends. For taxable years beginning after December 31, 1994, quarterly estimated tax payments will be required as provided under section 711 of the Uruguay Round Agreements, Public Law 103–465 (1994), page 230, and any administrative guidance issued by the Internal Revenue Service thereunder.

* * * * *

Margaret Milner Richardson,

Commissioner of Internal Revenue.

Approved: April 4, 1996.

Leslie Samuels,

Assistant Secretary of the Treasury.

[FR Doc. 96–11639 Filed 5–9–96; 8:45 am]

BILLING CODE 4830–01–U

EQUAL EMPLOYMENT OPPORTUNITY COMMISSION

29 CFR Part 1601

706 Agencies; Orange County (NC) Human Relations Commission and Palm Beach County (FL) Office of Equal Opportunity; Designation as Fair Employment Practices Agencies

AGENCY: Equal Employment Opportunity Commission.

ACTION: Final rule.

SUMMARY: The Equal Employment Opportunity Commission amends its regulations designating certain State and local fair employment practices agencies (706 Agencies) so that they may handle employment discrimination charges within their jurisdictions. Publication of this amendment effectuates the designation of the Orange County (NC) Human Relations Commission and the Palm Beach County (FL) Office of Equal Opportunity.

EFFECTIVE DATE: May 10, 1996.

FOR FURTHER INFORMATION CONTACT:

Boyce Nolan, Equal Employment Opportunity Commission, Office of Program Operations, Charge Resolution Review Program, 1801 L Street, N.W., Washington, D.C. 20507, Telephone (202) 663–4856.

SUPPLEMENTARY INFORMATION:

List of Subjects in 29 CFR Part 1601

Administrative practice and procedure, Equal employment opportunity, Intergovernmental relations.

Accordingly, title 29, chapter XIV, part 1601 of the Code of Federal Regulations is amended as follows:

PART 1601—PROCEDURAL REGULATIONS

1. The authority citation for part 1601 continues to read as follows:

Authority: 42 U.S.C. 2000e to 2000e–17; 42 U.S.C. 12111 to 12117.

2. Section 1601.74(a) is amended by adding in alphabetical order the following agencies:

§ 1601.74 Designated and notice agencies.

(a) * * *

Orange County (NC) Human Relations Commission

* * * * *

Palm Beach County (FL) Office of Equal Opportunity

* * * * *

Signed at Washington, D.C. this 2nd day of May, 1996.

For the Commission.

Gilbert F. Casellas,

Chairman.

[FR Doc. 96–11745 Filed 5–9–96; 8:45 am]

BILLING CODE 6750–01–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[AD–FRL–5503–3]

Hazardous Air Pollutants: Amendment to Regulations Governing Equivalent Emission Limitations by Permit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: On May 20, 1994, the Agency promulgated a rule in the Federal Register governing the establishment of equivalent emission limitations by permit, pursuant to section 112(j) of the Clean Air Act (Act). After the effective date of a Title V permit program in a State, each owner or operator of a major source in a source category for which the EPA was scheduled to, but failed to promulgate a section 112(d) emission standard will be required to obtain an equivalent emission limitation by permit. The permit application must be submitted to the Title V permitting authority 18 months after the EPA's missed promulgation date. This action amends the original Regulations Governing Equivalent Emission Limitations by Permit rule. This amendment delays the section 112(j) permit application deadline for all 4-year source categories listed in the regulatory schedule by 180 days until November 15, 1996. This action is needed to alleviate unnecessary paperwork for both major source owners or operators and permitting agencies.

EFFECTIVE DATE: May 10, 1996.

ADDRESSES: *Docket.* All information used in the development of this final action is contained in the preamble below. However, Docket No. A–93–32, containing the supporting information for the original Regulations Governing Equivalent Emission Limitations by Permit rule is available for public inspection and copying between 8:00 a.m. and 5:30 p.m., Monday through Friday at the Air and Radiation Docket and Information Center (6102), Room M–1500, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; telephone (202) 260–7548, fax (202) 260–4000. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. James Szykman or Mr. Anthony Wayne, Emission Standards Division (MD–13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541–2452 (Szykman) or (919) 541–5439 (Wayne).

SUPPLEMENTARY INFORMATION: In the Proposed Rules Section of this Federal Register, EPA is proposing a rule that is identical to this direct final rule. If significant, adverse comments are timely received on the proposed rule, the direct final rule will be withdrawn, and all such comments will be addressed in a subsequent final rule based on the proposed rule. If no significant, adverse comments are timely received on the proposed final rule, then the direct final rule remains effective upon publication, and no further action is contemplated on the parallel proposal published today.

The information presented in this preamble is organized as follows:

I. Background
II. Summary of Rule Change and Rationale
A. Permit Application Deadline
B. Effective Date
C. Judicial Review
III. Administrative Requirements
A. Docket
B. Regulatory Impact Analysis
C. Impact on Reporting Requirements
D. Impact on Small Entities
E. Reduction of Governmental Burden
F. Environmental Justice
G. Unfunded Mandates

I. Background

Section 112(e) of the Clean Air Act (the Act) requires the Agency to publish a schedule for promulgating regulations establishing hazardous air pollutants (HAP) emission standards for all source categories listed pursuant to Section 112 of the Act. The Act further directs that this regulatory schedule require the promulgation of emission standards for at least 40 source categories by 1992, for at least 25 percent of the listed categories by 1994, for at least 50 percent of the listed categories by 1997, and all remaining categories by the year 2000. These are commonly referred to as the 2-year, 4-year, 7-year, and the 10-year maximum achievable control technology (MACT) standards, respectively. This regulatory schedule was published by EPA on December 3, 1993 (58 FR 64931).

If EPA should fail to promulgate a MACT standard for a listed source category by 18 months after the date in the regulatory schedule, section 112(j) of the Act requires owners or operators of major sources within that source category to obtain a Title V permit, if the major source is located in a State with an approved Title V permit program. This permit will require compliance with an emission limitation equivalent to that which the major source would have been subject to had EPA promulgated a timely MACT standard for that source category.

On May 20, 1994, EPA issued a final rule for implementing section 112(j) (59 FR 26429). This rule requires major source owners or operators to submit a permit application by the date 18 months after a missed date on the regulatory schedule. In accordance with this regulation, the deadlines for submittal of permit applications are as follows:

Emission standard	Regulatory schedule	112(j) permit application deadline
4-year	11/15/94	5/15/96
7-year	11/15/97	5/15/99
10-year	11/15/00	5/15/02

II. Summary of Rule Change and Rationale

A. Permit Application Deadline

To date, EPA has promulgated several 4-year MACT standards and intends to promulgate MACT standards for all of the remaining 4-year source categories within the 18-month period following the date in the regulatory schedule. All of the remaining 4-year source categories for which MACT standards must be promulgated have court-ordered deadlines with the latest deadline coinciding with the section 112(j) permit application deadline of May 15, 1996.

In order for owners or operators of major sources to submit a timely permit application in the event that EPA would fail to promulgate a 4-year emission standard, applicants would have to begin preparation of these applications immediately. If EPA promulgates standards in accordance with the court-ordered schedule, this would result in an unnecessary burden for both the owners or operators and the Title V permitting agencies.

The EPA believes that ample authority for this rule revision exists under the *de minimis* doctrine. That doctrine allows EPA to promulgate a rule that avoids a statutory requirement if (1) following that requirement would yield an environmental benefit of trivial or no value, and (2) the statutory scheme is not so rigid as to preclude this result. *Alabama Power Co. v. Costle*, 636 F.2d 323, 360–61 (D.C. Cir 1979). The EPA believes both tests are met here. Regarding the first point, it should be intuitively apparent that requiring sources to complete applications for a case-by-case determination is pointless when it is very likely that EPA will promulgate the MACT standard within a timeframe that renders the entire case-by-case exercise moot. This is precisely the case with regard to the pending 4-year MACT standards, all of which are under a court-ordered deadline for issuance close to the date applications are due. Regarding the second test, the language of section 112(j)(2), requiring that applications be submitted on a date ''beginning'' 18 months after a deadline has been missed, and the clear intent of the statute that case-by-case determinations should be made where they will serve as a substitute for the pending MACT standard, together suggest a level of flexibility in the statutory scheme sufficient to allow resort to the *de minimis* rationale.

The EPA is amending the definition of ''Section 112(j) deadline'' in § 63.51 of the final rule to delay the section 112(j) permit application deadline for all 4-year source categories by 180 days until November 15, 1996. The EPA believes that this new application deadline will allow sufficient time to promulgate the remaining 4-year emission standards and is consistent with the intent of section 112(j). If EPA does promulgate the emission standards before this time, permit applications or reopenings will be governed by Title V requirements.

B. Effective Date

The EPA is publishing this rule as a final rule, and it is effective immediately upon publication. The Agency believes that this action is supported by the ''good cause'' exception in the Administrative Procedures Act, which permits an agency for ''good cause'' to proceed directly to a final rule where issuing a proposed rule would be ''impracticable, unnecessary, or contrary to the public interest'' [5 U.S.C. 553(b)(B)] and for ''good cause found'' [5 U.S.C. 553(d)] to dispense with the general requirement that a rule be published 30 days before its effective date. The EPA believes that good cause exists here to issue a final, immediately effective rule because of the nearness of the May 15, 1996, permit application deadline (for major sources in the 4-year source category) specified in the May 20, 1994 (59 FR 26429) final rule. If the changes in this rulemaking were only being proposed, then the May 15, 1996, deadline would still be in effect and this would negate the intent of this change to the rule to delay the permit application deadline until November 15, 1996, for sources in the 4-year source category. Furthermore, EPA views this action to delay the permit application deadline as noncontroversial.

C. Judicial Review

Under Section 307(b)(1) of the Act, judicial review of the actions taken by this final rule is available only by the filing of a petition for review in the U.S.

Court of Appeals for the District of Columbia Circuit within 60 days of publication of this action. Under Section 307(b)(2) of the Act, the requirements that are the subject of this final rule may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

III. Administrative Requirements

A. Docket

The docket for this regulatory action is A–93–32, the same docket as the original final rule, and a copy of today's amendment to the final rule will be included in the docket. The docket is an organized and complete file of all the information submitted to, or otherwise considered by, EPA in the development of the original rulemaking. The principal purposes of the docket are:

(1) To allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process, and

(2) To serve as the record in case of judicial review. The docket is available for public inspection at EPA's Air and Radiation Docket and Information Center, which is listed under the ADDRESSES section of this document.

B. Regulatory Impact Analysis

This rule was classified ''non-significant'' under Executive Order 12866 and therefore was not reviewed by the Office of Management and Budget.

C. Impact on Reporting Requirements

The information collection requirements of the previously promulgated rule for Regulations Governing Equivalent Emission Limitations by Permit were submitted to and approved by the Office of Management and Budget. A copy of this Information Collection Request (ICR) document (OMB control number 2060–0266) may be obtained from Sandy Farmer, OPPE Regulatory Information Division (2136), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, or by calling (202) 260–2740. Today's change to the final rule to delay the deadline for submittal of section 112(j) permit applications does not affect the information collection burden estimates made previously. Therefore, the ICR has not been revised.

D. Impact on Small Entities

The Regulatory Flexibility Act of 1980 requires the identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. Because this rulemaking imposes no economic impacts, adverse or otherwise, a Regulatory Flexibility Analysis has not been prepared.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small business entities.

E. Reduction of Governmental Burden

Executive Order 12875 (''Enhancing the Intergovernmental Partnership'') is designed to reduce the burden to State, local, and Tribal governments of the cumulative effect of unfunded Federal mandates. The Order recognizes the need for these entities to be free from unnecessary Federal regulation to enhance their ability to address problems they face and provides for Federal agencies to grant waivers to these entities from discretionary Federal requirements. The Order applies to any regulation that is not required by statute and that creates a mandate upon a State, local, or Tribal government. The EPA anticipates that there will be no additional cost burden imposed on State, local, and Tribal governments as a result of today's action. Indeed, the purpose of the action is to reduce unnecessary burden on permitting agencies.

F. Environmental Justice

Executive Order 12898 requires that each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority and low-income populations. Today's action will help ensure timely compliance and the application of consistent regulatory requirements by allowing the section 112(d) MACT standards to become effective without triggering an unnecessary section 112(j) process. Therefore, no adverse human health or environmental effects are anticipated as a result of today's action.

G. Unfunded Mandates

Under Section 202 of the Unfunded Mandates Reform Act of 1995 (''Unfunded Mandates Act''), the EPA must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in estimated costs to State, local, or tribal governments in the aggregate; or to the private sector, of $100 million or more. Under Section 205, the EPA must select the most cost-effective and least burdensome alternative that achieves the objectives of the rule and is consistent with statutory requirements. Section 203 requires the EPA to establish a plan for informing and advising any small governments that may be significantly or uniquely impacted by the rule.

The EPA has determined that the action promulgated today does not include a Federal mandate that may result in estimated costs of $100 million or more to either State, local, or tribal governments in the aggregate, or to the private sector. Therefore, the requirements of the Unfunded Mandates Act do not apply to this action.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practices and procedures, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: May 3, 1996.

Carol M. Browner,

Administrator.

For the reasons set out in the preamble, 40 CFR Part 63 is amended as follows:

PART 63—[AMENDED]

1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

2. In § 63.51, the definition of ''*Section 112(j) deadline*'' is revised to read as follows:

§ 63.51 Definitions.

* * * * *

Section 112(j) deadline means the date 18 months, after the date by which a relevant standard is scheduled to be promulgated under this part, except for all major sources listed in the source category schedule for which a relevant standard is scheduled to be promulgated by November 15, 1994, the section 112(j) deadline is November 15, 1996.

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[FR Doc. 96–11737 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

40 CFR Part 81

[AZR91–0003; FRL–5503–7]

Clean Air Act Reclassification; Arizona-Phoenix Nonattainment Area; PM_{10}

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this document EPA is making a final finding that the Phoenix Planning Area (PPA) has not attained the PM_{10} (particulate matter 10 microns or less in aerodynamic diameter) national ambient air quality standards (NAAQS) by the applicable attainment date in the Clean Air Act (CAA) for moderate PM_{10} nonattainment areas, December 31, 1994. This finding is based on EPA's review of PM_{10} ambient air quality data. As a result of this finding, the PPA is reclassified as a serious PM_{10} nonattainment area by operation of law. The intended effect of the reclassification is to allow the State 18 months from the effective date of this action to submit a new State Implementation Plan (SIP) demonstrating attainment of the PM_{10} NAAQS by December 31, 2001, the CAA attainment date for serious areas.

EFFECTIVE DATE: This action is effective on June 10, 1996.

FOR FURTHER INFORMATION CONTACT: Wallace Woo, Chief, Plans Development Section (A–2–2), Air Planning Branch, Air and Toxics Division, U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105, (415) 744–1207.

SUPPLEMENTARY INFORMATION:

I. Background

A. CAA Requirements and EPA Actions Concerning Designation and Classification

On November 15, 1990, the date of enactment of the 1990 Clean Air Act Amendments (CAA), PM_{10} areas meeting the qualifications of section 107(d)(4)(B) of the Act were designated nonattainment by operation of law. Once an area is designated nonattainment, section 188 of the Act outlines the process for classification of the area and establishes the area's attainment date. Pursuant to section 188(a), all PM_{10} nonattainment areas were initially classified as moderate by operation of law upon designation as nonattainment. These nonattainment designations and moderate area classifications were codified in 40 CFR part 81 in a Federal Register notice published on November 6, 1991 (56 FR 56694).

Under section 188(c)(1) of the CAA, the attainment deadline for all PM_{10} nonattainment areas originally classified as moderate was no later than December 31, 1994. Under section 188(d), EPA may, upon application by a state, extend the attainment deadline if the state has complied with all requirements and commitments pertaining to the area in the applicable implementation plan. In addition, in order to qualify for an extension there must have been no more than one exceedance of the 24 hour national ambient air quality standard (NAAQS) in the area in the year preceding the extension year, and the annual mean concentration of PM_{10} in the area for such year must be less than or equal to the standard. Under this provision, EPA may grant up to two one year extensions if these conditions have been met.

B. Reclassification as Serious Nonattainment

EPA has the responsibility, pursuant to sections 179(c) and 188(b)(2) of the CAA, of determining within six months of the applicable attainment date, whether PM_{10} nonattainment areas have attained the NAAQS. Section 179(c)(1) of the Act provides that these determinations are to be based upon an area's air quality as of the attainment date, and section 188(b)(2) is consistent with this requirement. EPA makes the determinations of whether an area's air quality is meeting the PM_{10} NAAQS based upon air quality data gathered at monitoring sites in the nonattainment area and entered into the Aerometric Information Retrieval System (AIRS). These data are reviewed to determine the area's air quality status in accordance with EPA guidance at 40 CFR part 50, Appendix K.

Pursuant to Appendix K, attainment of the annual PM_{10} standard is achieved when the annual arithmetic mean PM_{10} concentration is equal to or less than 50 $\mu g/m^3$. The annual average is determined by first calculating the average PM_{10} concentration for each calendar quarter. The annual average is then calculated by averaging the four calendar quarter averages. Attainment of the 24 hour standard is determined by calculating the expected number of exceedances of the 150 $\mu g/m^3$ limit per year. The 24 hour standard is attained when the expected number of exceedances is 1.0 or less. A total of three consecutive years of clean air quality data is generally necessary to show attainment of the 24 hour and annual standards for PM_{10}. A complete year of air quality data, as referred to in 40 CFR part 50, Appendix K, is comprised of all four calendar quarters with each quarter containing data from at least 75 percent of the scheduled sampling days.

Under section 188(b)(2)(A) of the CAA, a moderate PM_{10} nonattainment area must be reclassified as serious by operation of law after the statutory attainment date if the Administrator finds that the area has failed to attain the NAAQS. Pursuant to section 188(b)(2)(B), EPA must publish a notice in the Federal Register identifying those areas that failed to attain the standard and the resulting reclassification.

C. Effect of Reclassification

PM_{10} nonattainment areas reclassified as serious under section 188(b)(2) of the CAA are required to submit, within 18 months of the area's reclassification, SIP revisions providing for the implementation of best available control measures (BACM) no later than four years from the date of reclassification. The SIP also must contain a demonstration that the implementation of BACM will provide for attainment of the PM_{10} NAAQS no later than December 31, 2001. EPA has provided specific guidance on developing serious area PM_{10} SIP revisions in an addendum to the General Preamble to Title I of the Clean Air Act. See 59 FR 41998 (August 16, 1994).

D. Proposed Finding of Failure to Attain

On June 7, 1995 EPA proposed to find that the Phoenix Planning Area (PPA) had failed to attain the PM_{10} NAAQS by the applicable attainment date. 60 FR 30046. This proposed finding was based on PM_{10} monitoring data collected by Maricopa County during the years 1992 through 1994. The air quality monitoring data for the PPA showed three violations of the 24 hour PM_{10} NAAQS in 1992 and violations of the annual PM_{10} NAAQS in 1992 and 1993. The air quality monitoring data are discussed in detail in the Notice of Proposed Rulemaking (NPRM). 60 FR 30046, 30047. The following table summarizes the data on which EPA has based its finding of failure to attain:

Site	24 hour exceedances		Annual exceedances	
	Conc.	Date	1992	1993
4732 S. Central, Phoenix	171 $\mu g/m^3$	11/20/92		
	158 $\mu g/m^3$	12/2/92		
1475 E. Pecos, Chandler	156 $\mu g/m^3$	11/20/92	56 $\mu g/m^3$	58 $\mu g/m^3$

On October 20, 1995, the State requested, under section 188(d) of the CAA, that EPA extend the attainment deadline for the PPA from December 31, 1994 to December 31, 1995. This request was based on the lack of recorded exceedances of the PM_{10} NAAQS in 1994. In 1995, however, the PPA recorded two exceedances of the 24 hour NAAQS. On June 28, 1995 a concentration of 160 μg/m³ was recorded at the Chandler monitoring site, and on July 30, 1995 a concentration of 252 μg/m³ was recorded, also at the Chandler monitoring site. Additionally, the annual average concentration at the Chandler site in 1995 was 57.9 μg/m³. Thus, while the State technically qualified for a one year attainment date extension, the 1995 violations effectively moot this request because the area cannot qualify for a second extension. Therefore, EPA does not intend to act on the State's extension request.

II. Response to Comments on Proposed Finding

During the public comment period on EPA's proposed finding, the Agency received comment letters from: one State legislator; the Arizona Department of Environmental Quality (ADEQ); the Arizona Department of Transportation (ADOT); the Arizona Motor Transport Association; the Maricopa Association of Governments (MAG); and the Maricopa County Board of Supervisors. The issues raised in these comment letters are summarized below and are followed by EPA's responses.

A. Economic Impacts of EPA's Finding

Comment: EPA's determination in the proposed rulemaking that a finding of failure to attain the PM_{10} standard is not subject to certain requirements in Executive Order (E.O.) 12866 or the Unfunded Mandates Reform Act is incorrect, as is EPA's certification that this action does not have a significant impact on small entities.

Response: Under E.O. 12866, 58 FR 51735 (October 4, 1993), EPA is required to determine whether regulatory actions are significant and therefore should be subject to Office of Management and Budget (OMB) review, economic analysis, and the requirements of the E.O. The E.O. defines a ''significant regulatory action'' as one that is likely to result in a rule that may meet at least one of the four criteria identified in section 3(f), including, under paragraph (1), that the rule may ''have an annual effect on the economy of $100 million or more or adversely affect, in a material way, the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities.''

Sections 202, 203 and 205 of the Unfunded Mandates Reform Act of 1995 (Unfunded Mandates Act), 2 U.S.C. §§ 1501–1571, requires EPA to assess whether various actions undertaken in association with proposed or final regulations include a Federal mandate that may result in estimated costs of $100 million or more to the private sector, or to State, local or tribal governments in the aggregate.

Under the Regulatory Flexibility Act, 5 U.S.C. § 601 et seq., EPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C §§ 603 and 604. Alternatively, EPA may certify that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

Under section 188(b)(2) of the CAA, EPA findings of failure to attain are based upon air quality considerations, and reclassification of nonattainment areas must occur by operation of law in light of certain air quality conditions. Such findings and reclassification do not, in-and-of-themselves, impose any new requirements on any sectors of the economy. In addition, because the statutory requirements for the differently classified areas are clearly defined, and because those requirements are automatically triggered by classifications that, in turn, are triggered by air quality values, findings of failure to attain and reclassification cannot be said to impose a materially adverse impact on State, local, or tribal governments or communities.

This conclusion does not in any way reflect a determination regarding estimated or actual impacts of a reclassification on Arizona's economy. It is important to understand that the sole regulatory action that EPA is taking under the CAA involves only a factual finding of whether the Phoenix area attained the PM_{10} standards by December 31, 1994, the statutory attainment date for moderate areas. If EPA finds that the area has failed to attain by the deadline, then the area is reclassified as serious, not by EPA, but by operation of law. A finding by EPA that an area has failed to timely attain the PM_{10} standards is based on air quality monitoring data collected by Maricopa County and ADEQ from 1992 through 1994. The statute does not require any action on EPA's part, since the CAA specifies automatic reclassification of an area as a result of a finding that the area has not attained the PM–10 standards. See section 188(b)(2). Because EPA's role in making such a finding is essentially ministerial, the Agency has concluded that it does not impose any new requirements or mandates on any sector of the State economy.

For the above reasons, EPA has determined that the finding of failure to attain being made today would result in none of the effects identified in section 3(f) of E.O. 12866 and is therefore not a significant regulatory action, as defined in the E.O. Similarly, EPA has concluded that the finding of failure to attain does not constitute a Federal mandate within the meaning of the Unfunded Mandates Act. Furthermore, the Agency has certified that the redesignation of the attainment status of an area under section 107(d) of the CAA does not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act. See 46 FR 8709 (January 27, 1981). Because the regulatory impact of reclassification under section 188(b) of the CAA is no different substantively from that associated with designations, such actions are also not expected to have significant impacts on small entities.

EPA wishes to emphasize, however, that the reclassification of the Phoenix area is only the first step in developing a strategy to bring ambient concentrations of PM_{10} in the area to healthful levels. As with the State's moderate area SIP, which EPA approved on April 10, 1995 (60 FR 18010), development of a control strategy for the State's serious area SIP will involve an assessment of the economic feasibility of implementing any particular control measure. If Arizona determines that a measure cannot be implemented because it is not economically feasible, the State need only provide EPA with a reasoned justification for that determination. EPA believes there will be sufficient opportunity for ADEQ and other State agencies, local planning agencies, the general public, and the regulated community to assess the economic impacts of control measure implementation while they develop the serious area SIP.

B. State Monitoring and Modeling Study

Comment: ADEQ claims that reclassification is not necessary because the State and local governments have undertaken a study to better characterize the sources contributing to the nonattainment problem in the PPA.

The study will enable the State to define the control measures necessary to attain and maintain the PM_{10} NAAQS. As a result the PPA will be able to demonstrate attainment by implementing reasonably available control measures (RACM) rather than BACM.

Response: EPA acknowledges the difficulties in assessing the contributions from various sources to total PM_{10} concentrations and fully supports the State's efforts to accurately identify those sources which have caused the PPA to be in nonattainment of the standards. Nonetheless, section 188(b)(2) of the CAA does not afford EPA any discretion in determining whether the area has in fact attained the PM_{10} NAAQS by the statutorily mandated attainment date. EPA regulations generally require three years of ambient monitoring data in order to assess an area's attainment status. See 40 CFR part 50, Appendix K. As discussed in section I.D. of this notice, based on air quality data collected during the years 1992 through 1994, EPA has determined that the PPA has not attained the PM_{10} NAAQS.

Moreover, the State recently reported two additional violations of the PM_{10} NAAQS at the Chandler monitoring site in 1995. While for the purposes of this rulemaking EPA is only considering air quality data from 1992 through 1994, these 1995 violations further support EPA's determination that PPA has failed to attain the PM_{10} standard.

C. EPA's Current Review of the PM_{10} NAAQS

Comment: Reclassification of the PPA is untimely in light of the pending revision of the PM NAAQS. State and local agencies will have to spend considerable resources to develop a plan for a standard that may no longer be in effect.

Response: Section 109(d)(1) of the Clean Air Act requires that ''not later than December 31, 1980, and at five-year intervals thereafter'' EPA review and revise, if warranted, air quality criteria and national ambient air quality standards. EPA is currently under court order to complete its review of the particulate matter NAAQS by June 28, 1997.

This review may or may not result in a replacement and/or revision of the PM_{10} NAAQS. The Agency is currently considering the addition of a new PM NAAQS that targets fine particulate matter, such as particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers. However, the Agency is also considering retaining a PM_{10} standard. Although the PM NAAQS review process is incomplete at this time, recent epidemiologic studies show consistent positive associations of ambient PM exposure with adverse health effects, including mortality and morbidity. Given the significant health effects associated with PM, vigorous enforcement of the current PM_{10} requirements is critical to ensure protection of the public health. Until a revision of the NAAQS occurs, the current NAAQS and the requirements relating to them remain in force. In the event that a new NAAQS is promulgated, a transition policy that addresses current requirements and ensures protection of the public health will be developed.

D. Air Quality Monitoring

Comment: There should be a more detailed review of the circumstances surrounding the location of the two monitoring sites which recorded exceedances to insure that the locations are not anomalies improperly reflecting local conditions. It would not be appropriate to impose a classification upon the entire region due to what may be anomalies for just two sites out of nine.

Response: In order to meet Federal monitoring regulations, agencies which operate air monitoring networks are required to design these networks in order to meet certain monitoring objectives. These objectives are to determine: 1) the highest concentrations expected to occur in the area covered by the network; 2) representative concentrations in areas of high population density; 3) the impact on ambient pollution levels of significant sources or source categories; and 4) general background concentration levels. See 40 CFR part 58, Appendix D.

Both the South Phoenix and Chandler sites are located in order to measure PM_{10} concentrations in areas of high population density. The Maricopa County Environmental Services Department (MCESD) and ADEQ, the agencies responsible for operating the pollutant monitoring network in the PPA, conduct an annual review of the monitoring network as required by Federal regulations. See 40 CFR part 58.26 and 40 CFR part 58, Appendix F. EPA believes the South Phoenix and Chandler monitoring stations are correctly sited and meet all applicable Federal requirements.

Comment: According to section 2.11 of the Quality Assurance Handbook for Air Pollution Control, PM_{10} monitors have a precision error of ±10% when addressing the PM_{10} 24 hour NAAQS. Therefore, two of the recorded violations, with readings below 165 μg/m3, could be within the NAAQS when this error variation is accounted for.

Response: EPA's quality assurance procedures establish minimum acceptable operating limits for PM_{10} sampling equipment. The ±10% to which the commenter refers is not directly related to the final PM_{10} ambient concentration, but rather to the air flow rate through the PM_{10} sampler. The ambient concentration is calculated from the particle mass collected on a filter medium, the volume of air pulled through the filter, and the amount of time the sampler is operated. The ±10% to which the commenter refers is the acceptable range of deviation for the air flow rate through the sampler. Nevertheless, EPA recognizes the validity of the commenter's concern regarding the ±10% threshold. However, this 10% threshold is not an allowance or a leeway to adjust data, rather it is a limit which if exceeded alerts the field or laboratory monitoring personnel to a possible sample validity problem. Readings beyond the 10% threshold can mean heavy filter loading or decreases in the sampler flow rate. Air flow rates beyond this 10% threshold may necessitate invalidating all samples collected since the last sampler calibration. See Quality Assurance Handbook for Air Pollution Control, section 2.11.3.4, Sample Validation and Documentation.

Comment: According to EPA's Exceptional Event Guideline, high winds are defined as an hourly speed of greater than or equal to 30 mph or gusts equal to or greater than 40 mph with little or no precipitation. The western regional climate center in Reno, Nevada reported that November 20, 1992 was the windiest day of the quarter in the PPA with wind speeds up to 40 mph and no precipitation. Therefore the exceedance recorded on that date (156 μg/m3) should be classified as an exceptional event. Furthermore, all of the PM_{10} NAAQS violations in the PPA were impacted by short term construction activities. The Exceptional Event Guideline states that construction and demolition activities are exceptional events.

Response: EPA has established criteria and procedures to identify or ''flag'' data which may be affected by ''exceptional events'' in its ''Guideline on the Identification and Use of Air Quality Data Affected by Exceptional Events,'' July 1986 (Guideline). Under the flagging system, state and local air pollution control agencies are responsible for initially identifying and documenting data influenced by exceptional events. These agencies are expected to develop the appropriate

background information necessary to support a decision to flag an individual piece of data. The agencies must then submit the information to EPA for concurrence. Flagging a piece of data or data set does not exclude that data from being used for nonattainment designations or classifications. The actual exclusion would only be allowed if, as a result of a public review process, the responsible government agency, in this case EPA, determines that the data are inappropriate for use in a specific regulatory activity. Neither the MCESD nor ADEQ requested that these data be flagged as exceptional events, nor were these data proposed to be excluded from any specific regulatory action.

Notwithstanding the fact that the State did not initiate the flagging process, EPA would have evaluated whether the exceedances in question were affected by exceptional events had the commenter provided documentation demonstrating that they qualified as such. There are basically two issues which must be addressed in order to determine whether an exceedance of the NAAQS was due to an exceptional event. First, there must be a link between a specific PM_{10} generating activity (e.g., forest or structural fire, construction/demolition activity) and the suspect data. Second, there must be a determination that the activity is not likely to recur.

Regarding high winds, the commenter only referenced part of the definition in the Guideline of a high wind event. The definition in full is ''hourly windspeed of greater than or equal to 30 mph or gusts equal to or greater than 40 mph, with [little or] no precipitation. The high wind condition with [little or] no precipitation and dry soil must be associated with a significant contribution (estimated to be > 85% by weight) of crustal material on the PM sampling medium.'' The commenter did not provide any supporting information on the type of particulate matter which contributed to the PM_{10} exceedance on November 20, 1992. Furthermore, no information was provided to show that this wind event was itself exceptional, i.e. that it was not expected to recur.

As to construction activities, the commenter again only sites a portion of the definition of construction/demolition activities that would qualify as exceptional events. The Guideline states that construction/demolition activities that last for only a short period of time, are within a reasonable distance of the monitoring site and that are implementing all reasonable control measures may be flagged as exceptional events. Flagged data should be limited to sites that are classified as micro- or middle-scale and downwind with respect to the construction activity. The Chandler monitoring site is classified as a neighborhood scale site. See 40 CFR part 58, Appendix D for an explanation of the difference in spatial scales. As with the high wind claim, the commenter also did not address the likelihood of the construction activity's recurrence. In the State's approved moderate area PM_{10} SIP, construction activities are recognized as controllable sources of PM_{10} and are now regulated under Maricopa County Rule 310.

To summarize, the commenter did not provide any supporting information or data showing that the high winds or construction activities did, in fact, have a direct causal link to the PM_{10} NAAQS exceedances or, if so, the magnitude of the contribution from these sources. The commenter simply asserted that the high winds and construction activities occurred. Furthermore, the commenter did not address the likelihood of the recurrence of these conditions. In fact, the SIP development process is intended to prevent exceedances from anthropogenic activities such as construction by providing for planning by the State and local community to help ensure such activities adequately mitigate their contribution to PM_{10} air quality problems.

Comment: The two locations where violations were recorded are only two of nine SLAMS sites and data from the seven clean sites should also be considered in deciding whether the PPA should be reclassified. The recorded violations are only 14%, 5%, and 4% over the PM_{10} NAAQS and these values are not ''seriously'' in excess of the PM_{10} NAAQS.

Response: Maricopa County's nine station network is only a representative sample of the PPA's air quality. These nine stations cover 2,920 square miles. Monitoring is only conducted on a one in every six day schedule. Therefore, for every one sample taken, there are five days for which the air quality is unknown. If there were other sites set up to represent conditions similar to those of the violating sites, it is possible that more violations would have been recorded.

Pursuant to 40 CFR, part 50, Appendix K, an exceedance is defined as a value which is measured above the level of the 24 hour standard after rounding to the nearest 10 $\mu g/m^3$ (i.e. values ending in 5 or greater are rounded up). Therefore, had the highest recorded values in the 1992 to 1994 period been 154 $\mu g/m^3$ or less, the concentrations would not have been considered exceedances of the NAAQS. However, the PM_{10} concentrations recorded in the Phoenix area, 156 $\mu g/m^3$, 158 $\mu g/m^3$, and 171 $\mu g/m^3$, are above that level and are therefore considered exceedances.

Further, the claim that the exceedances were not ''seriously in excess'' of the NAAQS is without validity. The PM_{10} NAAQS are set at a level required to protect public health. The standards are designated levels, not ranges, of PM_{10} above which the air quality is considered unhealthy. The reclassification of the PPA is based on the fact that violations of the standards have occurred, and continue to occur, rather than on the severity of the violations.

E. National PM_{10} Standard

Comment: EPA should not apply a nationwide PM_{10} standard to an arid Southwest region such as the PPA.

Response: Section 109 of the CAA requires EPA to promulgate primary and secondary NAAQS for certain types of air pollutants. These standards are based on criteria which reflect current scientific knowledge of the effect of these pollutants on public health and welfare.

On July 1, 1987 EPA promulgated the NAAQS for PM_{10}. 52 FR 24663 (July 1, 1987). While the types of sources and the ability to control them differ from one area of the country to another, the human health effects of PM_{10} pollution are the same whether one resides in New York City or Phoenix. Therefore, in order to protect human health, the standards must be the same nationwide.

However, unlike the NAAQS, the SIP development process is intended to address variability in source types. While the CAA does impose certain minimum control requirements, ultimately it is up to the state and the affected local communities to choose the particular control measures that best address their unique air pollution problem. In developing the control measures, a state may consider the economic and technological feasibility of implementing a particular control measure.

III. Today's Final Action

EPA is today taking final action to find that the PPA did not attain the PM_{10} NAAQS by December 31, 1994, the CAA attainment date for moderate PM_{10} nonattainment areas. As a result of this final finding, the PPA is reclassified by operation of law as a serious PM_{10} nonattainment area.

IV. Executive Order (EO) 12866

Under E.O. 12866, 58 FR 51735 (October 4, 1993), EPA is required to determine whether regulatory actions

are significant and therefore should be subject to OMB review, economic analysis, and the requirements of the Executive Order. The Executive Order defines a ''significant regulatory action'' as one that is likely to result in a rule that may meet at least one of the four criteria identified in section 3(f), including, under paragraph (1), that the rule may ''have an annual effect on the economy of $100 million or more or adversely affect, in a material way, the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities.''

The Agency has determined that the finding of failure to attain finalized today would result in none of the effects identified in section 3(f). Under section 188(b)(2) of the CAA, findings of failure to attain and reclassification of nonattainment areas are based upon air quality considerations and must occur by operation of law in light of certain air quality conditions. They do not, in-and-of-themselves, impose any new requirements on any sectors of the economy. In addition, because the statutory requirements are clearly defined with respect to the differently classified areas, and because those requirements are automatically triggered by classifications that, in turn, are triggered by air quality values, findings of failure to attain and reclassification cannot be said to impose a materially adverse impact on State, local, or tribal governments or communities.

V. Regulatory Flexibility

Under the Regulatory Flexibility Act, 5 U.S.C. § 601 et seq., EPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C §§ 603 and 604. Alternatively, EPA may certify that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

As discussed in sections II.A. and IV of this notice, findings of failure to attain and reclassification of nonattainment areas under section 188(b)(2) of the CAA do not in-and-of-themselves create any new requirements. Therefore, I certify that today's final action does not have a significant impact on small entities.

VI. Unfunded Mandates

Under sections 202, 203 and 205 of the Unfunded Mandates Reform Act of 1995 (Unfunded Mandates Act), signed into law on March 22, 1995, EPA must assess whether various actions undertaken in association with proposed or final regulations include a Federal mandate that may result in estimated costs of $100 million or more to the private sector, or to State, local or tribal governments in the aggregate.

EPA believes, as discussed above, that the finding of failure to attain and reclassification of the Phoenix Planning Area are factual determinations based upon air quality considerations and must occur by operation of law and, hence, do not impose any federal intergovernmental mandate, as defined in section 101 of the Unfunded Mandates Act.

List of Subjects in 40 CFR Part 81

Environmental protection, Air pollution control, Intergovernmental relations, Particulate matter.

Dated: April 29, 1996.

Felicia Marcus,

Regional Administrator.

40 CFR part 81 is amended as follows:

PART 81—[AMENDED]

1. The authority citation for part 81 continues to read as follows:

Authority: 42 U.S.C. 7407, 7501–7515, 7601.

2. Section 81.303 is amended by revising the table for Arizona—PM–10, to read as follows:

§ 81.303 Arizona.

* * * * *

ARIZONA—PM–10

Designated Area	Designation		Classification	
	Date	Type	Date	Type
Cochise County:				
Paul Spur/Douglas planning area	11/15/90	Nonattainment	11/15/90	Moderate.
Township 23 South, Range 25 East (T23S, R25E):				
T23S,R26E				
T23S, R27E				
T23S, R28E				
T24S, R25E				
T24S, R26E				
T24S, R27E				
T24S, R28E				
Santa Cruz County:				
Nogales planning area	11/15/90	Nonattainment	11/15/90	Moderate.
The portions of the following Townships which are within the State of Arizona and lie east of 111° longitude:				
T23S, R13E				
T23S, R14E				
T24S, R13E				
T24S, R14E				
Rillito planning area	11/15/90	Nonattainment	11/15/90	Moderate.

ARIZONA—PM–10—Continued

Designated Area	Designation		Classification	
	Date	Type	Date	Type
Townships:				
T11S, R9E				
T11S, R10E				
T11S, R11E				
T11S, R12E				
T12S, R8E				
T12S, R9E				
T12S, R10E				
T12S, R11E				
T12S, R12E				
Pima County				
Ajo planning area	11/15/90	Nonattainment	11/15/90	Moderate.
Township T12S, R6W, and the following sections of Township T12S, R5W:				
a. Sections 6–8				
b. Sections 17–20, and				
c. Sections 29–32				
Maricopa and Pinal Counties				
Phoenix planning area	11/15/90	Nonattainment	6/10/96	Serious.
The rectangle determined by, and including—				
T6N, R3W				
T6N, R7E				
T2S, R3W				
T2S, R7E				
T1N, R8E				
Yuma County:				
Yuma planning area	11/15/90	Nonattainment	11/15/90	Moderate.
Townships:				
T7S-R21W, R22W;				
T8S-R21W, R22W, R23W, R24W				
T9S-R21W, R22W, R23W, R24W, R25W;				
T10S-R21W, R22W, R23W, R24W, R25W				
Pinal and Gila Counties:				
Hayden/Miami planning area	11/15/90	Nonattainment	11/15/90	Moderate.
Townships: T4S, R16E T5S, R16E T6S, R16E plus the portion of Township T3S, R16E that does not lie on the San Carlos Indian Reservation, and the rectangle formed by, and including, Townships				
T1N, R13E				
T1N, R15E				
T6S, R13E				
T6S, R15E				
Gila County (part):				
Payson: T10N, Sections 1–3, 10–15, 22–27, and 34–36 of R9E; T11N, Sections 1–3, 10–15, 22- 27, and 34–36 of R9E; T10–11N, R10E; T10N, Sections 4–9, 16–21, and 28–33 of R11E; T11N, Sections 4–9, 16–21, and 28–33 of R11E..	1/20/94	Nonattainment	1/20/94	Moderate.
Mohave County (part):				
Bullhead City: T21N, R20–21W, excluding Lake Mead National Recreation Area; T20N, R20- 22W; T19N, R21–22W excluding Fort Mohave Indian Reservation..	1/20/94	Nonattainment	1/20/90	Moderate.
Rest of State	11/15/90	Unclassifiable.		

* * * * *

[FR Doc. 96–11736 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

40 CFR Part 180

[PP 9F3714/R2214; FRL–5354–1]

RIN 2070–AB78

Fenoxaprop-Ethyl; Extension of Study Due Date and Time-Limited Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule extends the time-limited tolerances for fenoxaprop-ethyl from April 12, l996 to November 1, l997. This time extension was requested by AgrEvo USA Company to coordinate a delay in initiation of a repeat oncogenicity study required to change the interim (time-limited) tolerances, required for the use of fenoxaprop-ethyl in the culture of wheat, to permanent tolerances. The originial petitioner was Hoechst Celanese Corp. of North Somerville, NJ 08876. In l994 Hoechst Celanese Corp. and NOR-AM Chemical formed a partnership Company, AgrEvo USA Company; and AgrEvo USA

Company became the registrant of fenoxaprop-ethyl pesticide products.

EFFECTIVE DATE: May 10, 1996.

ADDRESSES: Written objections and hearing requests, identified by the docket number [PP 9F3714/R2214] may be submitted to: Hearing Clerk (1900), Environmental Protection Agency, Rm. M3708, 401 M St., SW., Washington, DC 20460. A copy of any objections and hearing requests filed with the Hearing Clerk should be identified by the docket number and submitted to: Public Response and Program Resources Branch, Field Operations Division (7506C), Office of Pesticide Programs, Environmental Protection Agency, 401 M St. SW., Washington, DC 20460. In person, bring copies of objections and hearing requests to: Rm. 1132, CM #2, 1921 Jefferson Davis Highway, Arlington, VA. 22202. Fees accompanying objections shall be labeled ''Tolerance Petition Fees'' and forwarded to: EPA Headquarters Accounting Operations Branch, OPP (tolerance Fees) P.O. Box 360277M, Pittsburgh, PA 15251.

A copy of objections and hearing requests filed with the Hearing Clerk may also be submitted electronically by sending electronic mail (e-mail) to: opp-docket@epamail.epa.gov. Copies of objections and hearing requests must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Copies of objections and hearing requests will also be accepted on disks in WordPerfect 5.1 file format or ASCII file format. All copies of objections and hearing requests in electronic form must be identified by the docket number [PP 9F3714/R2214]. No Confidential Business Information (CBI) should be submitted through e-mail. Electronic copies of objections and hearing requests on this rule may be filed online at many Federal Depository Libraries. Additional information on electronic submissions can be found below in this document.

FOR FURTHER INFORMATION CONTACT: By mail: Joanne Miller (PM 23), Registration Division (7505C), Office of Pesticide Programs, U. S. Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. Office location and telephone number: Rm. 237, CM #2, 1921 Jefferson Davis Hwy., Arlington, VA 22202, (Telephone No. (703–305–6226), e-mail: miller.joanne@epamail.epa.gov.

SUPPLEMENTARY INFORMATION: Interim tolerances that expire April 12, l996 were established for residues of fenoxaprop-ethyl on August 15, l991. The petitioner, Hoechst Celanese Corp., agreed to submitting a repeat mouse oncogenicity study within 4 years from the date of registration of fenoxaprop-ethyl pesticide products for use in the culture of wheat. The due date for the study data became April 12, l996, 4 years and 8 months from the date of first registration of fenoxaprop-ethyl in the culture of wheat. The added 8 months were to allow adequate time for the Agency's review of the study. The initiation of the mouse oncogenicity study was delayed due to the Agency's requirement for a repeat range finding study. The time line for submitting the study was extended to November 1, l996 to coordinate it with the time required for reviewing the range finding study. Considering the time required to review the study, the present action extends the time-limited tolerances to November 1, l997. The time alloted for Agency review of the study is presently 12 months. There is no information and experience with the pesticide that indicate that this action would pose significant risk to public health.

A ''Notice of Filing'' a request to amend pesticide petition (PP) 9F3714 by proposing to amend 40 CFR 180.430 to extend the time-limited tolerances for residues of the herbicide Fenoxyaprop-ethyl was published on in the Federal Register on April 3, 1996 (61 FR 14772–14773) (FRL–5358–4). There were no substantive responses to the notice. Only a typographical error was noted from the public. That error is corrected in the present Final rule.

Any person adversely affected by this regulation may, within 30 days after publication of this document in the Federal Register, file written objections to the regulation and may also request a hearing on those objections. Objections and hearing requests must be filed with the Hearing Clerk, at the address given above (40 CFR 178.20). A copy of the objections and/or hearing requests filed with the Hearing Clerk should be submitted to the OPP docket for this rulemaking. The objections submitted must specify the provisions of the regulation deemed objectionable and the grounds for the objections (40 CFR 178.25). Each objection must be accompanied by the fee prescribed by 40 CFR 180.33(i). If a hearing is requested, the objections must include a statement of the factual issue(s) on which a hearing is requested, the requestor's contentions on such issues, and a summary of any evidence relied upon by the objector (40 CFR 178.27). A request for a hearing will be granted if the Administrator determines that the material submitted shows the following: There is genuine and substantial issue of fact; there is a reasonable possibility that available evidence identified by the requestor would, if established, resolve one or more of such issues in favor of the requestor, taking into account uncontested claims or facts to the contrary; and resolution of the factual issue(s) in the manner sought by the requestor would be adequate to justify the action requested (40 CFR 178.32).

EPA has established a record for this rulemaking under docket number [PP 9F3714/R2214] (including any comments and data submitted electronically). A public version of this record, including printed, paper versions of electronic comments, which does not include any information claimed as CBI, is available for inspection from 8 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The public record is located in Room 1132 of the Public Response and Program Resources Branch, Field Operations Division (7506C), Office of Pesticide Programs, Environmental Protection Agency, Crystal Mall #2, 1921 Jefferson Davis Highway, Arlington, VA.

Electronic comments may be sent directly to EPA at:

opp-docket@epamail.epa.gov .

Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption.

The official record for this rulemaking, as well as the public version, as described above will be kept in paper form. Accordingly, EPA will transfer any copies of objections and hearing requests received electronically into printed, paper form as they are received and will place the paper copies in the official rulemaking record which will also include all comments submitted directly in writing. The official rulemaking record is the paper record maintained at the address in ''ADDRESSES'' at the beginning of this document.

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether the regulatory action is ''significant'' and therefore subject to all the requirements of the Executive Order (i.e., Regulatory Impact Analysis, review by the Office of Management and Budget (OMB)). Under section 3(f), the order defines ''significant'' as those actions likely to lead to a rule (1) having an annual effect on the economy of $100 million or more, or adversely and materially affecting a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local or tribal governments or communities (also known as ''economically significant''); (2) creating

serious inconsistency or otherwise interfering with an action taken or planned by another agency; (3) materially altering the budgetary impacts of entitlement, grants, user fees, or loan programs; or (4) raising novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this Executive Order.

Pursuant to the terms of this Executive Order, EPA has determined that this rule is not ''significant'' and is therefore not subject to OMB review.

Pursuant to the requirements of the Regulatory Flexibility Act (Pub. L. 96-354, 94 Stat. 1164, 5 U.S.C. 601-612), the Administrator has determined that regulations establishing new tolerances or raising tolerance levels or establishing exemptions from tolerance requirements do not have a significant economic impact on a substantial number of small entities. A certification statement to this effect was published in the Federal Register of May 4, 1981 (46 FR 24950).

List of Subjects in 40 CFR Part 180

Environmental protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: April 29, 1996.

Stephen L. Johnson,

Director, Registration Division, Office of Pesticide Programs.

Therefore, 40 CFR, chapter I, part 180 is amended as follows:

PART 180—[AMENDED]

1. The authority citation for part 180 continues to read as follows:

Authority: 21 U.S.C. 346a and 371.

2. In § 180.430 by revising paragraph (b) to read as follows:

§ 180.430 Fenoxaprop-ethyl; tolerances for residues.

* * * * *

(b) Time-limited tolerances, to expire November 1, 1997, are established for the combined residues of the herbicide fenoxaprop-ethyl [(±) ethyl 2-[4-[(6-chloro-2-benzoxazolyl)oxy]phenoxy]propanoate] and its metabolites [2-[4-[(6-chloro-2-benzoxazoly)oxy]phenoxy]propanoic acid and 6-chloro-2,3-dihydrobenzoxazol-2-one], each expressed as fenoxaprop-ethyl, in or on the following raw agricultural commodities:

Commodities	Parts per million
Cattle, fat	0.05
Cattle, meat	0.05
Cattle, mbyp	0.05
Goats, fat	0.05
Goats, meat	0.05
Goats, mbyp	0.05
Hogs, fat	0.05
Hogs, meat	0.05
Hogs, mbyp	0.05
Horses, fat	0.05
Horses, meat	0.05
Horses, mbyp	0.05
Milk	0.02
Sheep, fat	0.05
Sheep, meat	0.05
Sheep, mbyp	0.05
Wheat, grain	0.05
Wheat, straw	0.05

[FR Doc. 96–11338 Filed 5–09–96; 8:45 am]

BILLING CODE 6560–50–F

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 22 and 90

[WT Docket No. 96–18; PP Docket No. 93–253; FCC 96–183]

Future Development of Paging Systems and Implementation of Section 309(j) of the Communications Act; Competitive Bidding

AGENCY: Federal Communications Commission.

ACTION: Interim measure; modification.

SUMMARY: In this *First Report and Order* in WT Docket No. 96–18 and PP Docket No. 93–253, the Commission modifies the interim measures imposed in the *Notice of Proposed Rulemaking (NPRM*) in this docket. In the *NPRM,* the Commission addressed how paging applications should be treated during the pendency of this rulemaking, and imposed an across-the-board freeze on new applications for paging licenses with an exception for Common Carrier Paging (CCP) and Private Carrier Paging (PCP) licensees with nationwide exclusivity. The Commission is modifying the interim freeze imposed in the *NPRM* by allowing all incumbent paging licensees subject to the interim freeze to apply for additional transmission sites on the same channel, on a primary basis, within 65 kilometers (40 miles) of an operating transmission site. An application must be accompanied by a certification that the applicant is an incumbent paging licensee, and the proposed site is within 65 kilometers (40 miles) of an authorized transmission site that was licensed to the same applicant on the same channel on or before February 8, 1996 and which is operational as of the date the application for the additional transmitter site is filed. All applications filed by CCP incumbent licensees and 929 MHz PCP incumbent licensees on exclusive channels will be put on Public Notice to allow for competing applications to be filed.

The Commission resumes processing all pending non-mutually exclusive applications that were filed by incumbents with the Commission on or before February 8, 1996. The February 8, 1996 freeze interrupted the 30 or 60 day filing window in some cases. Therefore, the Wireless Telecommunications Bureau will release a Public Notice with attached copies of the prior Public Notices containing the pending paging applications. All pending applications filed by incumbents on or before February 8, 1996 that were not on Public Notice for the required 30 or 60 days, will be deemed to continue to be on Public Notice for the remaining amount of time until the required 30 or 60 day window for filing competing applications expires.

The Commission's objective in modifying the interim freeze is to allow the incumbent paging licensees the flexibility needed to expand paging systems to continue to serve their customers and convert to flexible wide-area synchronous protocol technology during the interim period, while preventing an increase in telecommunications investment fraud.

EFFECTIVE DATE: May 10, 1996.

FOR FURTHER INFORMATION CONTACT: Mika Savir, Commercial Wireless Division, Wireless Telecommunications Bureau, at (202) 418–0620.

SUPPLEMENTARY INFORMATION: This *First Report and Order* in WT Docket No. 96–18 and PP Docket No. 93–253, adopted April 22, 1996, and released April 23, 1996, is available for inspection and copying during normal business hours in the FCC Reference Center, Room 230, 1919 M Street N.W., Washington D.C. The complete text may be purchased from the Commission's copy contractor, International Transcription Service, Inc., 2100 M Street, N.W., Suite 140, Washington D.C. 20037, (202) 857–3800)). Synopsis of *First Report and Order:*

I. Background

1. In this docket, the Commission is examining the paging regulations in light of the statutory objective of regulatory symmetry for all Commercial Mobile Radio Services (CMRS) established in the Omnibus Budget Reconciliation Act of 1993, Pub. L. No.

103–66 (1993 Budget Act). The 1993 Budget Act amended the Communications Act to divide all mobile services into two categories, CMRS and private mobile radio service (PMRS), and mandated that substantially similar mobile services receive comparable regulatory treatment. In the *CMRS Third Report and Order,* Implementation of Sections 3(n) and 332 of the Communications Act, GN Docket No. 93–252, *Third Report and Order,* 59 FR 59945 (November 21, 1994) (*CMRS Third Report and Order*), the Commission concluded that CCP and PCP are substantially similar services and should be subject to comparable regulation. Under Section 6002(c)(2)(B) of the 1993 Budget Act, reclassified PCP licensees retain their PMRS status on a grandfathered basis until three years after the date of enactment of the legislation which occurred on August 10, 1993. PMRS paging services, as well as CMRS paging services, are subject to the interim and final measures in this proceeding.

2. In the *NPRM,* Revision of Part 22 and Part 90 of the Commission's Rules to Facilitate Future Development of Paging Systems and Implementation of Section 309(j) of the Communications Act—Competitive Bidding, WT Docket No. 96–18, *Notice of Proposed Rulemaking,* 61 FR 06199 (February 16, 1996) (*NPRM*), the Commission proposed a transition to geographic market area licensing for all paging services. In the *NPRM,* the Commission also proposed to adopt competitive bidding rules for mutually exclusive paging applications. Additionally, the Commission suspended acceptance of new applications for paging channels, as of February 8, 1996. The Commission allowed incumbents to make minor modifications to their existing systems, so long as the modifications did not increase their composite interference contour. The Commission also allowed all licensees with nationwide exclusivity to continue to add sites without restrictions.

3. The Commission received comments and reply comments on the interim proposals. Based on the arguments raised by the commenters, the Commission concludes that partially lifting the interim freeze for incumbent licensees would be in the public interest.

II. First Report and Order

A. Interim Freeze

4. In the *NPRM,* the Commission requested comment on an expedited basis on whether, during the pendency of this proceeding, incumbents should be allowed to file new applications to expand or modify their existing systems in a way that would expand their existing interference contours, with such modifications receiving only secondary site authorization. The Commission also requested comment from interested parties on other alternatives for allowing expansion or modification of existing sites during the interim period. Commenters offered numerous suggestions for partially lifting the freeze. The Commission concurs with the commenters that partially lifting the interim freeze is necessary to allow incumbents flexibility in serving their customers and upgrading their equipment, and that these additions or modifications should be given primary, not secondary, status.

5. Commenters all generally oppose the interim freeze, particularly for incumbent licensees. Most of the commenters also oppose secondary site licensing, on the grounds that it would discourage investment, encourage speculation, and could result in future loss of service to the public. Several commenters propose that as an interim measure incumbent licensees be permitted to add sites to within 40 miles of an operating site. Commenters also offer other suggestions such as that incumbents be allowed to add sites if the service area of the new site overlaps with existing authorized sites by a minimum of 50 percent, or that they be allowed to expand their systems as long as the expansions do not interfere with other current adjacent licensees.

6. Commenters also argue that the freeze gives undue advantage to nationwide carriers, while decreasing the ability of the remainder of the industry to compete. One commenter noted that the paging freeze gives a competitive edge to Personal Communications Services (PCS). Several commenters observed that the paging industry is converting to a flexible wide-area synchronous protocol which requires additional sites.

7. A group of paging carriers and paging equipment manufacturers, the Coalition for a Competitive Paging Industry (Coalition), filed an Emergency Petition for immediate lifting of the freeze. The Commission incorporates the Petition into the record of this proceeding. The Coalition also filed reply comments on the interim licensing issue, which make many of the same arguments set forth in the Petition. To the extent that the Commission grants limited relief from the freeze for incumbent licensees, the Petition is granted. In all other respects, the Commission denies the Petition. The Coalition argues that the freeze is unlawful, arbitrary and capricious, and an abuse of discretion on the grounds that: (1) There is insufficient spectrum available on currently allocated paging channels to accommodate additional systems; (2) paging carriers who are upgrading their technology are prevented by the freeze from filing the modification applications required to implement their networks; and (3) the Commission has discriminated against carriers serving local and regional markets by exempting nationwide carriers from the freeze. The Coalition also filed an *ex parte* letter proposing that: (1) The Commission accept applications filed by incumbents to expand or modify existing systems; (2) applications would be subject to Public Notice and competing applications if required under the rules in effect as of February 7, 1996; (3) requests for exclusivity on 929 MHz channels would be granted in appropriate cases under the rules in effect on February 7, 1996; and (4) mutually exclusive applications would not be processed until the conclusion of the rulemaking unless the parties could agree to eliminate mutual exclusivity through agreement.

8. The Federal Trade Commission (FTC) filed comments to, *inter alia,* explain the extent of the telecommunications investment fraud associated with paging licenses. According to the FTC, the investment fraud is of two basic types: (1) License ''application mills'' that sell application preparation services for acquisition of wireless licenses for a fee of several thousand dollars per license; and (2) ''build-out'' schemes, in which investors are sold interests in limited liability companies or partnerships that claim they will acquire licenses and build and operate telecommunications systems. Both of these schemes are carried out by telemarketers calling unsophisticated consumers and deceiving them about the profitability of the licenses, and the consumers generally lose their entire investment. In January 1996, the FTC filed six actions as part of ''Project Roadblock'' against the telemarketers who sold application preparation and acquisition services for paging licenses. The FTC observes that in the Commission's database of pending 931 MHz applications, over 72 percent of the applicants are individuals, rather than businesses. The FTC also notes that 92 percent of license holders on 929 MHz channels are individuals. According to the FTC, the high percentage of individual applicants strongly suggests that many of these individuals are victims of the

application mills. The FTC observes that telemarketing fraud has caused the Commission to process thousands of license applications for consumers who will never provide telecommunications services to the public, and contributes substantially to the backlog of pending applications and the quantity of mutually exclusive applications. According to the FTC, the freeze against accepting new applications has a strong deterrent effect on application mill fraud.

9. The Commission explains that it rejects the arguments of the Coalition and other commenters that the freeze is unlawful because it was not based on prior notice and comment. The Commission notes that the suspension of acceptance of applications is a procedural action that does not require notice and comment under the Administrative Procedure Act (APA). Additionally, the Commission notes that it has imposed similar freezes without prior notice and comment in other rulemaking proceedings when there was a proposal to make the transition to geographic area licensing and auction rules.

10. The Commission also rejects the arguments of commenters that imposing a freeze was arbitrary or an abuse of the Commission's discretion. The freeze remains essential to ensure that the goals of the rulemaking are not compromised. The primary argument raised by commenters against the freeze is that there is limited ''white space'' to be auctioned; however this contention is undermined by the commenters' argument that the freeze is causing severe economic harm. If there were in fact little or no white space left to be licensed, maintaining the freeze would have minimal impact. The Commission notes that while paging channels are heavily encumbered, there is some available spectrum that is of considerable value to applicants.

11. The Commission also states that the freeze is necessary to combat telemarketing schemes involving paging application fraud. The FTC estimates that fraudulent investment schemes centered on acquiring FCC licenses for wireless technologies have been the most prevalent telemarketing investment scams of the 1990s, costing consumers hundreds of millions of dollars. If the freeze were to be lifted, it could inadvertently encourage a resumption of fraudulent activity by application mills seeking to induce unsophisticated investors into filing applications. The Commission also stated a concern that the proposal to use auctions in this service may stimulate speculative activity by parties seeking to warehouse free spectrum.

12. The Commission notes that the commenters have raised valid reasons to support partially lifting the freeze for the remainder of the interim period: the paging industry needs flexibility to make modifications and additions to systems to continue to serve their customers; licensees are in the process of converting to flexible wide-area synchronous protocol technology to increase data delivery speeds and therefore require additional base stations to maintain the existing service area; and the nationwide carriers may have a competitive advantage over the non-nationwide incumbent licensees in the local and regional markets. The Commission concludes that the interim freeze should be partially lifted for incumbent paging licensees.

13. As of May 10, 1996, the Commission is modifying the interim freeze imposed in the *NPRM*, by allowing all incumbent paging licensees subject to the interim freeze to apply for additional transmission sites on the same channel, on a primary basis, within 65 kilometers (40 miles) of an operating transmission site. An application will be accepted only if it is accompanied by a certification that (1) the applicant is an incumbent paging licensee, and (2) the proposed site is within 65 kilometers (40 miles) of an authorized transmission site that was licensed to the same applicant on the same channel on or before February 8, 1996 and which is operational as of the date the application for the additional transmitter site is filed. The applications from incumbent paging licensees on a non-nationwide CCP channel and incumbent paging licensees on an exclusive PCP channel will be placed on public notice and subject to competing applications within the applicable filing window.

14. The Commission states that while it will accept initial applications as described above only from incumbents, but it will not limit eligibility to file competing applications once the incumbent's initial application is filed. If no competing application is filed, the incumbent's initial application can be granted. If a competing application is filed, both applications will be treated as mutually exclusive and will be held in abeyance until the conclusion of this proceeding.

B. Interference Contour

15. In the *NPRM*, the Commission stated that incumbent licensees on all bands except the nationwide channels could add sites to existing systems, or modify existing sites during the pendency of this rulemaking proceeding, if the addition or modification does not expand the interference contour of the incumbent's existing system. The Commission stated in a footnote that for such purposes, the interference contour would be based on a median field strength of 21 dBμV/m, and referenced the proposed mathematical formulas for calculating the service and interfering contours for paging systems.

16. The Commission's reference to the proposed formula to calculate the interference contour during the interim period caused some confusion among the commenters. The commenters object to the proposed formula to calculate the interference contour during the interim period because it would shrink their current interference contour. The commenters also contend that this proposal was unlawful because it was retroactive and was not subject to the required notice and comment procedures.

17. The Commission clarifies that it is not applying the proposed interference contour formula on a retroactive basis to any current sites. For purposes of interim licensing, incumbents may use the interference contour defined under the current rules to determine whether internal sites may be added or modified. The Commission notes that this will allow 939 MHz licensees to make internal system changes so long as they do not expand the composite circular interference contour of their existing stations as defined in Section 22.537(f) of the rules. The Commission also clarifies that the tables in Section 22.537(f) may be used on an interim basis by licensees on 929 MHz exclusive channels to determine where stations may be added.

C. Exempt Services

18. Commenters have asked the Commission to clarify that the freeze does not apply to Basic Exchange Telecommunications Radio Systems (BETRS), Special Emergency Radio Service (SERS), and two-way mobile telephone service on the two-way channels listed in Section 22.561 and these rural telephone channels should be exempt from the freeze. The Commission observes that this proceeding was initiated to examine the paging regulations in light of the statutory objective of regulatory symmetry for all CMRS established in the 1993 Budget Act. BETRS are licensed under the Rural Radiotelephone Service, which is a fixed service, not a mobile service, and by definition is not CMRS. Implementation of Sections 3(n) and

332 of the Communications Act, GN Docket No. 93–252, *Second Report and Order*, 59 FR 18493 (April 19, 1994) (*CMRS Second Report and Order*). Therefore, BETRS are not subject to the interim paging freeze. Similarly, conventional Rural Radiotelephone Service provided on the channels listed in Sections 22.561 and 22.563 is not a mobile service, and is not subject to the interim freeze in this proceeding. The Commission is also exempting SERS from the interim freeze.

D. Processing of Pending Applications

19. In this *First Report and Order*, the Commission establishes consistent procedures for processing applications filed on or before February 8, 1996. Pursuant to Sections 22.120(d) and 22.127, applications for 150 MHz and 450 MHz channels are placed on Public Notice for 30 days, and applications for 931 MHz channels are on Public Notice for 60 days to allow other applicants to file competing applications. All applications that were filed with the Commission on or before February 8, 1996 have been on Public Notice; however, the February 8, 1996 interim freeze interrupted the 30 or 60 day filing window in some cases. After the release of this *First Report and Order*, the Wireless Telecommunications Bureau will release a Public Notice with attached copies of the prior Public Notices containing the pending paging applications. Once the Public Notice is released, all pending applications filed by incumbents that were not on Public Notice for the required 30 or 60 days will be deemed to be on Public Notice for the remaining amount of time until the required 30 or 60 day period for filing competing applications expires. The Commission will not issue an additional Public Notice for these pending CCP applications. Upon expiration of the remaining filing period for these pending CCP applications filed by incumbents, the applications that are not mutually exclusive will be processed.

20. All 929 MHz PCP exclusive applications filed by incumbents which were processed through the frequency coordinator, and filed with the Commission on or before February 8, 1996, and are not mutually exclusive, will be processed. Applications for PCP channels submitted by incumbents to the frequency coordinator but not filed with the Commission prior to February 8, 1996, may be resubmitted to the frequency coordinator, and then may be filed with the Commission, provided that the applicant certifies that the applicant is an incumbent licensee with an operating system.

E. Canadian and Mexican Coordination During the Interim Period

The Commission states that in cases where coordination must be obtained in Canadian or Mexican border areas, licensees must continue to file applications with the Commission to allow for such coordination under the interim licensing procedures.

III. Conclusion

22. The Commission concludes that the revisions to the interim measures adopted in this *First Report and Order* will enable paging licensees to continue expansion of their systems and enhance the quality of service to the public while this proceeding is pending. At the same time, the limitations on new applications during the interim period will prevent spectrum warehousing and deter application fraud. The Commission emphasizes that the measures set forth in this *First Report and Order* are interim measures only, and that the long-term proposals for geographic licensing of paging channels will be determined in the future.

IV. Procedural Matters and Ordering Clauses

A. Regulatory Flexibility Analysis

As required by Section 604 of the Regulatory Flexibility Act, the Commission has prepared a Final Regulatory Flexibility Analysis for the Interim Measures in the *First Report and Order* of the expected impact on small entities of the modification of the interim measures.

Statement of the Need for and Objectives of Measures: In the *First Report and Order*, the Commission is modifying the interim measures, specifically, the interim freeze on new paging applications imposed in the *Notice of Proposed Rulemaking*, to permit incumbent paging licensees to apply for additional licenses to add transmission sites to existing paging systems on the same channel as the existing systems, provided that the additional transmission site is within 65 kilometers (40 miles) from an operating transmission site in the applicant's system. This modification of the interim measure will allow paging companies additional flexibility to expand their systems during the interim period.

Summary of Significant Issues Raised by Comments to the Initial Regulatory Flexibility Analysis (IRFA): There were no comments to the IRFA regarding the interim measures.

All significant alternatives are discussed in the *First Report and Order*.

B. Paperwork Reduction Act

This *First Report and Order* contains a new information collection. The Commission, as part of its continuing effort to reduce paperwork burdens, has submitted this to Office of Management and Budget (OMB) for emergency approval under the Paperwork Reduction Act of 1995, Public Law 104–13. The Commission has requested OMB approval by April 29, 1996.

Further Information: For additional information concerning the information collections contained in this *First Report and Order*, contact Dorothy Conway at (202) 418–0217 or via the Internet at dconway@fcc.gov.

Supplementary Information:

Title: Revision of Part 22 and Part 90 of the Commission's Rules to Facilitate Future Development of Paging Systems and Implementation of Section 309(j) of the Communications Act—Competitive Bidding.

Type of Review: New Collection.

Respondents: Common Carrier Paging licensees and Private Carrier Paging licensees filing applications for additional transmission sites.

Number of Respondents: Approximately 2000.

Estimated Time Per Response: Approximately 0.08 hours for each respondent to read and sign the certification.

Total Annual Burden: A burden of approximately 160 hours.

Needs and Uses: On February 8, 1996, the Commission adopted a *Notice of Proposed Rule Making (NPRM)* that examines ways to establish a comprehensive and consistent regulatory scheme that will simplify and streamline licensing procedures and provide a flexible operating environment for both common carrier and private paging services. The *NPRM* imposed an interim across-the-board freeze on new paging applications.

On April 22, 1996, the Commission adopted the *First Report and Order* that modified the interim freeze imposed in the *NPRM* to allow the incumbents in the paging industry the flexibility needed to serve the public, and upgrade to more spectrally efficient equipment. The *First Report and Order* allows incumbent common carrier paging and private carrier paging licensees to expand their current paging systems by applying for additional transmission sites on the same channel within 65 kilometers (40 miles) from their existing operating transmission sites. This modification of the interim measures is limited to incumbent licensees. Paging applicants must certify in writing that: (1) The applicant is an incumbent

paging licensee, and (2) the proposed site is within 65 kilometers (40 miles) of an authorized transmission site that was licensed to the same applicant on the same channel on or before February 8, 1996 and which is operational as of the date the application for the additional transmitter site is filed. This modification of the interim measures is effective May 10, 1996.

C. Ex Parte Rules—Non-Restricted Proceeding

Ex parte presentations are permitted except during the Sunshine Agenda period, provided they are disclosed as provided in the Commission's rules, 47 CFR 1.1202, 1.1203, 1.1206(a).

D. Authority

The above action is authorized under the Communications Act, §§ 4(i), 303(r), 309(c), 309(j), and 332, 47 U.S.C. 154(i), 303(r), 309(c), 309(j), and 332, as amended.

E. Ordering Clauses

It is Ordered that, pursuant to the authority of sections 4(i), 303(r), 309(c), 309(j), and 332 of the Communications Act of 1934, as amended, 47 U.S.C. 154(i), 303(r), 309(c), 309(j), and 332, this *First Report and Order* is adopted and the interim freeze set forth in the *Notice of Proposed Rulemaking* in this docket is modified, effective May 10, 1996 as set forth herein.

It is further ordered that the Emergency Petition for Immediate Withdrawal of Freeze filed by the Coalition for a Competitive Paging Industry on February 28, 1996, is granted to the extent discussed herein, and denied in all other respects.

List of Subjects

47 CFR Part 22

Communication common carriers, Reporting and recordkeeping requirements.

47 CFR Part 90

Common carriers, Reporting and recordkeeping requirements.

Federal Communications Commission.

William F. Caton,

Acting Secretary.

[FR Doc. 96–11643 Filed 5–9–96; 8:45 am]

BILLING CODE 6712–01–P

47 CFR Part 73

Radio Broadcasting Services; Various Locations

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Commission, on its own motion, editorially amends the Table of FM Allotments to specify the actual classes of channels allotted to various communities. The changes in channel classifications have been authorized in response to applications filed by licensees and permittees operating on these channels. This action is taken pursuant to *Revision of Section 73.3573(a)(1) of the Commission's Rules Concerning the Lower Classification of an FM Allotment*, 4 FCC Rcd 2413 (1989), and the *Amendment of the Commission's Rules to permit FM Channel and Class Modifications [Upgrades] by Applications*, 8 FCC Rcd 4735 (1993).

EFFECTIVE DATE: May 10, 1996.

FOR FURTHER INFORMATION CONTACT: Kathleen Scheuerle, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's *Report and Order*, adopted April 26, 1996, and released May 6, 1996. The full text of this Commission decision is available for inspection and copying during normal business hours in the Commission's Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractors, International Transcription Services, Inc., 2100 M Street, NW., Suite 140, Washington, DC 20037, (202) 857–3800.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Part 73 of title 47 of the Code of Federal Regulations is amended as follows:

PART 73—[AMENDED]

1. The authority citation for part 73 continues to read as follows:

Authority: Secs. 303, 48 Stat., as amended, 1082; 47 U.S.C. 154, as amended.

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under Arkansas, is amended by removing Channel 233A and adding Channel 233C3 at West Helena.

3. Section 73.202(b), the Table of FM Allotments under California, is amended by removing Channel 276A and adding Channel 276B1 at Oakhurst, by removing Channel 286A and adding Channel 286B1 at Pacific Grove, and by removing Channel 239A and adding Channel 242A at Twentynine Palms.

4. Section 73.202(b), the Table of FM Allotments under Kansas, is amended by removing Channel 284A and adding Channel 284C3 at Fort Scott.

5. Section 73.202(b), the Table of FM Allotments under Maine, is amended by removing Channel 249A and adding Channel 249B.

6. Section 73.202(b), the Table of FM Allotments under Montana, is amended by removing Channel 233C and adding Channel 233C1 at Great Falls and by removing Channel 257C and adding Channel 257A at Red Lodge.

7. Section 73.202(b), the Table of FM Allotments under Nebraska, is amended by removing Channel 249A and adding Channel 249C1 at Holdrege.

8. Section 73.202(b), the Table of FM Allotments under New Mexico, is amended by removing Channel 266C3 and adding Channel 266A at White Rock.

9. Section 73.202(b), the Table of FM Allotments under South Carolina, is amended by removing Channel 232A and adding Channel 232C3 at Goose Creek.

Federal Communications Commission.

Andrew J. Rhodes,

Acting Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 96–11763 Filed 5–9–96; 8:45 am]

BILLING CODE 6712–01–F

47 CFR Part 73

[MM Docket No. 95–153; RM–8702]

Radio Broadcasting Services; Tillamook, OR

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Commission, at the request of Brian Lord, allots Channel 231A to Tillamook, OR, as the community's second local FM transmission service. *See* 60 FR 55358, October 31, 1995. Channel 231A can be allotted to Tillamook in compliance with the Commission's minimum distance separation requirements with a site restriction of 5.8 kilometers (3.6 miles) west, at coordinates 45–27–27 North Latitude; 123–55–00 West Longitude, to avoid a short-spacing to Station KPDQ-FM, Channel 229C, Portland, Oregon. Canadian concurrence in the allotment has been received since Tillamook is located within 320 kilometers (200 miles) of the U.S.-Canadian border. With this action, this proceeding is terminated.

DATES: Effective June 17, 1996. The window period for filing applications will open on June 17, 1996, and close on July 18, 1996.

FOR FURTHER INFORMATION CONTACT: Leslie K. Shapiro, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's *Report and Order,* MM Docket No. 95–153, adopted April 16, 1996, and released May 3, 1996. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, International Transcription Service, Inc., (202) 857–3800, 2100 M Street, NW., Suite 140, Washington, DC 20037.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Part 73 of title 47 of the Code of Federal Regulations is amended as follows:

PART 73—[AMENDED]

1. The authority citation for part 73 continues to read as follows:

Authority: Secs. 303, 48 Stat., as amended, 1082; 47 U.S.C. 154, as amended.

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under Oregon, is amended by adding Channel 231A at Tillamook.

Federal Communications Commission.

Andrew J. Rhodes,

Acting Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 96–11762 Filed 5–9–96; 8:45 am]

BILLING CODE 6712–01–F

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47 CFR Part 73

[MM Docket No. 95–162; RM–8714]

Radio Broadcasting Services; Wellsville, NY

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Commission, at the request of Erin Communications, Inc., substitutes Channel 278A for Channel 228A at Wellsville, NY, and modifies Station WJQZ(FM)'s license to specify operation on the alternate Class A channel. *See* 60 FR 55821, November 3, 1995. The substitution of channels could allow Station WJQZ(FM) to improve its facilities from its present 3 kW to 6 kW. With this action, this proceeding is terminated.

EFFECTIVE DATE: June 17, 1996.

FOR FURTHER INFORMATION CONTACT: Leslie K. Shapiro, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's *Report and Order,* MM Docket No. 95–162, adopted April 16, 1996, and released May 3, 1996. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, International Transcription Service, Inc., (202) 857–3800, 2100 M Street, NW., Suite 140, Washington, DC 20037.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Part 73 of title 47 of the Code of Federal Regulations is amended as follows:

PART 73—[AMENDED]

1. The authority citation for part 73 continues to read as follows:

Authority: Secs. 303, 48 Stat., as amended, 1082; 47 U.S.C. 154, as amended.

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under New York, is amended by removing Channel 228A and adding Channel 278A at Wellsville.

Federal Communications Commission.

Andrew J. Rhodes,

Acting Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 96–11761 Filed 5–9–96; 8:45 am]

BILLING CODE 6712–01–F

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47 CFR Part 97

[PR Docket No. 93–305; FCC 96–184]

Implementation of a Vanity Call Sign System

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: This action revises the amateur service rules to make clear that a renewal application, filed at the address specified by the Commission on the same date as the license expiration, is timely. Also, an application for a vanity call sign, filed at the address specified in the Wireless Telecommunications Bureau Fee Filing Guide on the same date as the license expiration, is timely. The rule amendments are necessary so that licensees will know that they have continuing authority to operate, pending action on their applications. The effect of this action is to assure licensees that their operating authority is continued until the final disposition of the applications.

EFFECTIVE DATE: June 10, 1996.

FOR FURTHER INFORMATION CONTACT: Maurice J. DePont, Federal Communications Commission, Washington, D. C. 20554, (202) 418–0690.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's *Second Memorandum Opinion and Order,* adopted April 23 , 1996, and released May 3, 1996. The complete text of this Commission action, including the rule amendments, is available for inspection and copying at the Federal Communications Commission, Room 246, 1919 M Streeet, N. W., Washington, D. C. The complete text of this *Second Memorandum Opinion and Order* may also be obtained from the Commission's copy contractor, International Transcription Services, Inc., 2100 M Street, N.W., Suite 140, Washington, D.C. 20037, telephone (202) 857–3800.

Summary of Second Memorandum Opinion and Order

1. By this action, we are amending the amateur service rules to state that an application for license renewal, received at the address specified by the Commission on the same date as the license expiration, is timely.

2. Also, by this action, we are amending the amateur service rules to state that an application for a vanity call sign, received at the address specified in the Wireless Telecommunications Bureau Fee Filing Guide on the same date as the license expiration, is timely.

3. These amendments will assure licensees that they have continuing authority to operate until there is a final disposition of the application.

4. The amended rules are set forth below, effective June 10, 1996.

5. This *Second Memorandum Opinion and Order* and the rule amendments are issued under the authority contained in 47 U.S.C. 154(i) and 303(r).

List of Subjects in 47 CFR Part 97

Call signs, Radio.

Federal Communications Commission.

William F. Caton,

Acting Secretary.

Final Rules

Part 97 of Chapter I of Title 47 of the Code of Federal Regulations is amended as follows:

PART 97—AMATEUR RADIO SERVICE

1. The authority citation for Part 97 continues to read as follows:

Authority: 48 Stat. 1066, 1082, as amended: 47 U.S.C. §§ 154, 303. Interpret or apply 48 Stat. 1064–1068, 1081–1105, as amended; 47 U.S.C. 151–155, 301–609, unless otherwise noted.

2. Section 97.21 is amended by revising the last sentence of paragraphs (a)(3)(i) and (a)(3)(ii) to read as follows:

§ 97.21 Application for a modified or renewed license.

(a) * * *

(3) * * *

(i) * * * When the application for renewal of the license has been received by the FCC at 1270 Fairfield Road, Gettysburg, PA 17325–7245 on or before the license expiration date, the license operating authority is continued until the final disposition of the application.

(ii) * * * When the application has been received at the proper address specified in the Wireless Telecommunications Bureau Fee Filing Guide on or before the license expiration date, the license operating authority is continued until final disposition of the application.

* * * * *

[FR Doc. 96–11644 Filed 5–9–96; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

49 CFR Parts 18 and 90

[OST Docket No. OST–96–1343]

RIN 2105–AC44

Audits of State and Local Governments

ACTION: Final rule.

SUMMARY: In connection with the President's Regulatory Reform Initiative, the Department of Transportation (DOT) is reviewing all of its existing regulations. As a result of the review we have identified 49 CFR part 90 as an unnecessary regulation that should be removed. The rule essentially repeats verbatim the requirements of Office Management and Budget (OMB) Circular A–128, Audits of State and Local Governments. The rule is being replaced by minor amendments to 49 CFR part 18, to reference Federal audit requirements in OMB circulars.

DATES: This regulation is effective June 10, 1996.

FOR FURTHER INFORMATION CONTACT: Robert G. Taylor, U.S. Department of Transportation, Office of Acquisition and Grant Management, M–62, 400 Seventh Street, S.W., Room 9401, Washington, D.C. 20590, (202) 366–4289.

SUPPLEMENTARY INFORMATION:

Background

Audit requirements for State and local grantees are based on the Single Audit Act of 1984 (31 U.S.C. 7501–7507). These requirements have been implemented in OMB Circular A–128, Audits of State and Local Governments (50 FR 19114–19119). These audit requirements have been implemented in DOT in 49 CFR part 18 and in 49 CFR part 90, Audits of State and Local Governments. Part 90 is merely a republication of OMB Circular A–128. The Department has determined that part 90 is unnecessary, and has decided to rescind part 90 and add a reference to OMB Circular A–128 in Section 26, Non-Federal Audits, of part 18.

This action represents no change in DOT audit policy, but makes implementation of OMB Circular A–128 consistent with the manner other OMB management circulars are implemented. A copy of OMB Circular A–128 can be obtained from the information contact above.

A reference to OMB Circular A–133, ''Audits of Institutions of Higher Education and Other Nonprofit Institutions,'' has also been added to Section 26 of part 18 to inform subrecipients of State or local governments who are institutions of higher education or other nonprofit organizations of the audit requirements imposed on them. This requirement is contained in 49 CFR part 19, Uniform Administrative Requirements for Grants and Agreements With Institutions of Higher Education, Hospitals, and Other Nonprofit Organizations.

Regulatory Analyses and Notices

Executive Order 12866 (Regulatory Planning and Review) and DOT Regulatory Policies and Procedures

The Department of Transportation has determined that this rulemaking is not a significant regulatory action within the meaning of Executive Order 12866, nor a significant regulation under the Department's Regulatory Policies and Procedures. The action is a reissuance of current requirements. Because of this, the Department certifies that this regulatory action is nonsignificant under the Department of Transportation's Regulatory Policies and Procedures.

Regulatory Flexibility Act of 1980

The Regulatory Flexibility Act (5 U.S.C. 605(b)) requires that, for each rule with a ''significant economic impact on a substantial number of small entities,'' an analysis be prepared describing the rule's impact on small entities and identifying any significant alternatives to the rule that would minimize the economic impact on small entities. We certify that these regulations will not have a significant economic impact on a substantial number of small entities because they do not affect the amount of funds provided in the covered programs, but rather reissue administrative and procedural requirements.

Executive Order 12612 (Federalism Assessment)

This action has been analyzed in accordance with the principles and criteria contained in Executive Order 12612. The rules primarily apply to State and local governments, but this is merely a reissuance of current requirements. Accordingly, the Department certifies that this action does not have sufficient Federalism implications to warrant a full Federalism Assessment under the principles and criteria contained in Executive Order 12612.

Paperwork Reduction Act

There are no additional collection of information requirements in this final rule.

Justification to Issue Final Rule

Under the Administrative Procedure Act, to issue a final rule without an NPRM, it is necessary to make a finding that issuing an NPRM would be impractical, unnecessary, or contrary to the public interest. This action involves no substantive change in policy, but makes implementation of OMB Circular A–128 consistent with implementation of other OMB Circulars. Instead of a rule that republished OMB Circular A–128, we are incorporating the Circular by reference. Since an NPRM would not result in the receipt of useful information, its issuance is unnecessary. The action is in the public interest because, in accordance with the President's regulatory reinvention efforts, we are eliminating a duplicative regulation.

List of Subjects

49 CFR Part 18

Accounting, Contract programs, Grant programs, Grants administration, Intergovernmental relations, Reporting and recordkeeping requirements.List of

49 CFR Part 90

Audits, Grant programs, Grants administration.

Issued this 1st day of May 1996 at Washington, D.C.

Federico Peña,

Secretary of Transportation.

Accordingly, for the reasons set forth above, Subpart A of Title 49 of the Code of Federal Regulations is amended as set forth below.

PART 18—UNIFORM ADMINISTRATIVE REQUIREMENTS FOR GRANTS AND COOPERATIVE AGREEMENTS TO STATE AND LOCAL GOVERNMENTS

1. The authority for Part 18 continues to read as follows:

Authority: 49 USC 322(a).

2. Section 18.26 is amended by adding paragraphs (d) and (e) to read as follows:

§ 18.26 Non-Federal Audits.

* * * * *

(d) Governmental recipients and subrecipients are subject to the Single Audit Act of 1984 (31 U.S.C. 7501–7507), and OMB Circular A–128, ''Audits of State and Local Governments.''

(e) Subrecipients of Federal assistance that are institutions of higher education or other nonprofit organizations are subject to OMB Circular A–133, Revised, ''Audits of Institutions of Higher Education and Other Non-Profit Institutions.'' State and local governments may choose to apply the provisions of OMB Circular A–128 to certain public hospitals and institutions of higher education.

PART 90—[REMOVED]

3. Part 90 is hereby removed.

[FR Doc. 96–11607 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–62–P

Surface Transportation Board

49 CFR Parts 1164 and 1311

[STB Ex Parte No. 545]

Removal of Obsolete Regulations Concerning Owner-Operators

AGENCY: Surface Transportation Board.

ACTION: Final rule.

SUMMARY: The Surface Transportation Board (the Board) is removing from the Code of Federal Regulations obsolete regulations concerning owner-operators.

EFFECTIVE DATE: May 10, 1996.

FOR FURTHER INFORMATION CONTACT: Beryl Gordon, (202) 927–7513. [TDD for the hearing impaired: (202) 927–5721.]

SUPPLEMENTARY INFORMATION: Effective January 1, 1996, the ICC Termination Act of 1995, Pub. L. No. 104–88, 109 Stat. 803 (ICCTA) abolished the Interstate Commerce Commission (ICC) and established the Board within the Department of Transportation. Section 204(a) of ICCTA provides that ''[t]he Board shall promptly rescind all regulations established by the [ICC] that are based on provisions of law repealed and not substantively reenacted by this Act.''

Generally, prior to enactment of the Motor Carrier Act of 1980 (MCA–80), motor common and contract carriers needed licenses from the ICC (certificates for common carriers, permits for contract carriers) in order to operate. These licenses were based on public convenience and necessity and fitness standards. Motor common and contract carriers could only charge rates that were filed with the ICC in tariffs or schedules.

The regulations involved here relaxed these regulatory requirements for owner-operators transporting food. The part 1164 regulations were based on former 49 U.S.C. 10922(b)(4)(E), 10923(b)(5)(A), and 11145(c). The part 1311 regulations were based on former 49 U.S.C. 10762(a)(1) and 10762(g), as well as former sections 10922(b)(4)(E) and 10923(b)(5)(A). Under the Trucking Industry Regulatory Reform Act (TIRRA), Title II of the Hazardous Materials Transportation Act Amendments of 1994, Pub. L. No. 103–311 (August 26, 1994), and the ICCTA, these statutory provisions were repealed, and we are accordingly removing the obsolete part 1164 and part 1311 regulations.

PART 1164—LICENSING

Sections 5(a)(3) and 10(a)(2) of the MCA–80 provided exceptions for owner-operators to the licensing provisions then generally applicable for obtaining certificates and permits. These sections of the MCA–80 were codified, as here relevant, at former 49 U.S.C. 10922(b)(4)(E) and 49 U.S.C. 10923(b)(5)(A). Owner-operators were allowed to obtain operating authority from the ICC to transport food and certain other commodities [1] through a fitness-only application procedure.[2] The ICC issued regulations implementing the new statute in *Owner-Operator Food Transportation*, 132 M.C.C. 521 (1981) *(Owner-Operator)*.[3]

TIRRA again amended former sections 10922 and 10923. Sections 207 and 208 of TIRRA eliminated the provisions of 49 U.S.C. 10922(b)(4)(E) and 49 U.S.C. 10923(b)(5)(A) and also modified other parts of sections 10922 and 10923 to apply the fitness-only standard to all non-household goods motor property common and contract carrier applicants. *See Revised MC-Licensing Appl. Forms and Regs.*, 10 I.C.C.2d 386, 387 (1994).[4] Thus, since the passage of TIRRA, owner operators have been able to obtain authority to transport food products under that standard regardless of the annual tonnage and ownership of the vehicle.[5]

Because former sections 10922(b)(E)(5), 10923(b)(5)(A), and 11145(c) have been eliminated, we will remove the obsolete regulations at 49 CFR part 1164.

PART 1311—RATE FILINGS

Section 5(a) of the MCA–80 modified for owner-operators the requirement to file tariffs and schedules: former 49 U.S.C. 10762 was amended by the addition of a new subsection (g) mandating the streamlining of rate filing requirements of motor carriers holding authority issued under former section 10922(b)(4)(E) and 10923(b)(5)(a). Also, former section 10762(a)(1) was amended

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[1] These commodities were food and other edible products included for human consumption (excluding alcoholic beverages and drugs), agricultural limestone, and fertilizers and other soil conditioners. For brevity, these commodities will be referred to as food products.

[2] The statute limited this provision to transportation by the owner of the vehicle, except in emergency situations, and to situations in which the annual tonnage of food products transported did not exceed the annual tonnage of exempt commodities transported. Former 49 U.S.C. 11145(c) required the ICC to ''streamline'' the annual method of reporting tonnage.

[3] These regulations were originally found in 49 CFR part 1138, but they were redesignated at 49 CFR part 1164 on November 1, 1982 (47 FR 49534). They defined the term ''emergency situations'' and promulgated an annual reporting requirement to certify compliance with the statute's annual tonnage limitation.

[4] Effective January 1, 1995, the ICC was to issue authorities to carriers upon finding that the applicant was in compliance with (1) ICC regulations and safety requirements; (2) DOT safety fitness requirements; and (3) minimum financial responsibility requirements established by the ICC pursuant to 49 U.S.C. 10927.

[5] Truck licensing was again changed under the ICCTA. Permanent licensing for motor carriers of property was eliminated. 49 U.S.C. 13902. Now, motor carriers are registered for a term determined by the Secretary of Transportation based on fitness standards (safety and insurance) similar to those in TIRRA. A two-year transition period is established to allow motor common and contract carriers to be issued certificates and permits under the TIRRA framework. 49 U.S.C. 13902(d). Although ICCTA eliminates the distinction between motor common and contract carriage, each carrier can be separately registered during the transition period.

to require the filing of only minimum rates for owner-operator transportation of food products. In *Owner-Operator, supra,* the ICC adopted regulations at 49 CFR part 1311 that permitted owner-operators of food products to file, in lieu of tariffs or schedules, a letter statement containing the transportation services performed and the minimum rates.[6]

Section 206 of TIRRA further amended former section 10762(a)(1) by removing the tariff filing requirement for individually (as distinguished from collectively) set rates of motor common carriers of property (other than household goods and carriers involved with water carriers in the noncontiguous domestic trade). Motor contract carriers were no longer required to file actual or minimum rates.[7]

The ICCTA further modified the rate filing requirements. Former section 10762(g) was removed. Now, under 49 U.S.C. 13702, motor carriers only need to file a tariff with the Board for transportation in noncontiguous domestic trade (with certain exceptions).

Because the statutory bases for the part 1311 regulations have been repealed, we are eliminating these obsolete rules.

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

List of Subjects

49 CFR Part 1164

Foods, Freight, Motor carriers, Reporting and recordkeeping requirements.

49 CFR Part 1311

Foods, Freight, Motor carriers.

Decided: April 24, 1996.

By the Board, Chairman Morgan, Vice Chairman Simmons, and Commissioner Owen.

Vernon A. Williams,

Secretary.

PARTS 1164 AND 1311—[REMOVED]

For the reasons set forth in the preamble and under the authority of 49 U.S.C. 721(a), title 49, chapter X of the Code of Federal Regulations is amended by removing parts 1164 and 1311.

[FR Doc. 96–11742 Filed 5–9–96; 8:45 am]

BILLING CODE 4915–00–P

[6] The ICC later eliminated by exemption the requirement that motor contract carriers file a schedule of rates. *Exemption—Mtr. Contr. Car.—Tariff Filing Requirements,* 133 M.C.C. 150 (1983), *aff'd sub nom. Central & Southern Motor Freight Ass'n* v. *United States,* 757 F.2d 301 (D.C. Cir. 1985), *cert. denied,* 474 U.S. 1019 (1985).

[7] Although sections 207 and 208 of TIRRA eliminated former sections 10922(b)(4)(E) and 10923(b)(5)(A), TIRRA did not remove former section 10762(g), the provision for streamlined rate filing for owner-operator transportation of food products.

Proposed Rules

Federal Register
Vol. 61, No. 92
Friday, May 10, 1996

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

9 CFR Part 92

[Docket No. 95–053–1]

Horses Imported Into the United States

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Proposed rule.

SUMMARY: We are proposing to amend the horse importation regulations to clarify the information required on the application for a permit to import horses into the United States and to clarify health certificate requirements for imported horses that transit another country en route to the United States. We believe that these proposed actions are necessary to ensure that importers of horses provide adequate and accurate information on import permit applications and to ensure that horses are properly handled from the time the horses leave their farm of origin until the horses arrive in the United States. These proposed amendments appear necessary to ensure the continued protection of the health of horses in the United States.

DATES: Consideration will be given only to comments received on or before July 9, 1996.

ADDRESSES: Please send an original and three copies of your comments to Docket No. 95–053–1, Regulatory Analysis and Development, PPD, APHIS, suite 3C03, 4700 River Road Unit 118, Riverdale, MD 20737–1238. Please state that your comments refer to Docket No. 95–053–1. Comments received may be inspected at USDA, room 1141, South Building, 14th Street and Independence Avenue SW., Washington, DC, between 8 a.m. and 4:30 p.m., Monday through Friday, except holidays. Persons wishing to inspect comments are requested to call ahead on (202) 690–2817 to facilitate entry into the comment reading room.

FOR FURTHER INFORMATION CONTACT: Dr. Joyce Bowling, Staff Veterinarian, Import/Export Animals, National Center for Import and Export, VS, APHIS, 4700 River Road Unit 39, Riverdale, MD 20737–1231, (301) 734–8170.

SUPPLEMENTARY INFORMATION:

Background

The regulations in 9 CFR part 92 (referred to below as ''the regulations'') govern the importation into the United States of specified animals, including horses, to prevent the introduction of various animal diseases into the United States.

Under § 92.304, importers must apply for a permit to import horses into the United States. The regulations state that importers must provide certain information, including the route of travel, for horses being imported into the United States, and the required information must appear on the application for an import permit.

Under § 92.314, horses imported into the United States must be accompanied by a health certificate completed by a salaried veterinary officer of the national government of the country of origin indicating the horses' freedom from communicable diseases such as contagious equine metritis and African horse-sickness. Additionally, § 92.314 requires that ''a horse presented for importation from a country where it has been for less than 60 days shall be accompanied by a like certificate similarly issued by a salaried veterinary officer of the national government of each country in which the horse has been during the 60 days immediately preceding shipment from the last country from which it is shipped to the United States.''

We are proposing to amend the regulations by adding definitions of the terms ''country of origin'' and ''country of transit'' and by adding an explanation of the words ''route of travel.''

We propose to define ''country of origin'' as the ''country in which the horse was born, was raised, and remained until shipment to the United States, or the country into which the horse was legally imported and has remained for a period of not less than 60 days prior to shipment to the United States.'' In cases of horses legally imported into their country of origin, we have determined that a 60-day residency requirement would maintain consistency with other requirements in the regulations. We would define ''country of origin'' in the regulations because, in the past, there has been some confusion on the part of importers concerning the meaning of the term ''country of origin,'' especially when a horse is moved to another country for shipment to the United States. In limited cases, the country from which the horse was directly shipped to the United States was mistakenly identified as the country of origin on the horse's import permit. We also propose to define ''country of transit'' as a ''country through which a horse travels en route from the country of origin to the United States.'' A complete list of the countries of transit should appear in the ''route of travel'' section of the import permit application, but, on occasion, importers have mistakenly omitted countries through which a shipment of horses traveled en route to the United States.

In addition, we propose to specify that ''route of travel'' must include a list of all of the countries that the horse will transit en route to the United States, all of the modes of transportation that will be used to move the horse from the country of origin to the port of entry in the United States, and all of the locations where the horse will be offloaded prior to arrival at the U.S. port of entry. In the past, in addition to neglecting to list all of the countries of transit, some importers have mistakenly omitted information on the modes of transportation used to transport a shipment of horses and locations where the shipment of horses will be offloaded. Because different countries have different disease statuses, and the risk of the horses' exposure to disease increases when shipped by ground transportation and when offloaded at some locations within countries of transit, a complete assessment of the import risk associated with a particular shipment of horses is only possible when all of the essential information is available on the import permit application.

We believe that by defining the terms ''country of origin'' and ''country of transit'' and by clarifying the words ''route of travel,'' importers would know exactly what information needs to be provided on the application for an import permit. This action would improve compliance with the regulations and continue to ensure that

horses intended for importation into the United States do not pose a disease risk to the domestic horse population.

We are also proposing to clarify the regulations concerning locations for offloading. Currently, the regulations do not specify appropriate locations where horses may be offloaded in countries of transit. We are proposing to require that if, during shipment to the United States, a horse is offloaded in a country of transit, then that horse must be offloaded in a facility that is capable of being cleaned and disinfected and that is approved by the country of transit's Ministry of Agriculture for the offloading of in-transit horses. We are also proposing to specify that while the horse is offloaded in the facility, the horse must be kept separate from all other horses. This action would reduce the risk that horses intended for importation into the United States would come into contact with other horses of unknown disease status en route to the United States.

Additionally, we are proposing to clarify the requirements concerning health certificates from countries of transit. We propose to amend § 92.314 to ensure that the regulations clearly state that if, during shipment to the United States, a horse is offloaded in a country of transit, then that horse must undergo a veterinary inspection and obtain a health certificate from a salaried veterinary officer of the national government of the country of transit in which the horse is offloaded. If a horse is offloaded in more than one country of transit, then that horse would be required to undergo a veterinary inspection and obtain a health certificate from a salaried veterinary officer of the national government in every country of transit in which the horse is offloaded. This clarification of the requirements would ensure that any communicable diseases in horses intended for importation into the United States are diagnosed as early as possible and that appropriate action is taken to prevent those diseases from being carried into the United States.

We propose that, after performing the veterinary inspection, the veterinary officer of a country of transit must complete a form that describes the horse being shipped, certifies that a health inspection has been performed on that horse, and assures that the horse is free from evidence of communicable diseases. We are proposing that the certification read, ''The animals described on this form have been given a careful veterinary inspection and found to be free from evidence of communicable disease and, in my opinion, are fit to travel.'' The veterinarian would sign this certificate to attest to the fact that the horse has been inspected, determined to be free of evidence of communicable diseases, and judged to be in a condition that would indicate that the animal would be in the same health upon arrival at its destination in the United States as when inspected in the country of transit. This inspection and certification would ensure that horses imported into the United States present a minimal disease risk to the U.S. horse population.

In addition, we propose to specify that the veterinary inspection must be performed in the country of transit no earlier than 24 hours before the horse is reloaded on a transport vehicle for shipment to the United States. We are proposing a 24-hour time limit in order to provide flexibility in the timing of the veterinary inspection while ensuring that the inspection takes place as close to the time of the horse's departure from a country of transit as possible.

If a horse intended for importation into the United States travels through any countries other than its country of origin and the United States but is not offloaded in a country of transit, we propose that the owner of the horse, or the owner's representative, must sign a certification statement prior to the horse's shipment from the country of origin that certifies that the horse will be shipped directly to the United States. We are proposing that the certification read, ''The horse will be sent directly from the premises of origin to the premises of destination without coming into contact with other equine animals not accompanied by an official health certificate, in vehicles cleaned and disinfected in advance with a disinfectant officially recognized in the country of origin.'' This statement would have to be presented upon the horse's arrival in the United States. If, however, for reasons beyond the importer's or shipper's control, the horse experiences an unscheduled offloading in a country of transit, then the horse would have to undergo a veterinary inspection and obtain a health certificate from a salaried veterinary officer of the national government of the country of transit.

Miscellaneous

We are proposing to make other minor, nonsubstantive changes to § 92.304, such as correcting punctuation. Additionally, we are proposing to amend §§ 92.304 and 92.314 by adding a reference to the end of each section for the Office of Management and Budget control number assigned to approved information collection and recordkeeping requirements.

Executive Order 12866 and Regulatory Flexibility Act

This proposed rule has been reviewed under Executive Order 12866. The rule has been determined to be not significant for the purposes of Executive Order 12866 and, therefore, has not been reviewed by the Office of Management and Budget.

We are proposing to clarify the information required on the application for a permit to import horses into the United States and to clarify health certificate requirements for imported horses that transit another country en route to the United States.

As this proposal simply clarifies the regulations and as most horses arrive in the United States with proper documentation, we do not expect a significant number of importers to be affected by this action. For importers not currently in compliance with the regulations, any cost incurred in complying with the regulations should be offset by the costs currently incurred by importers when a shipment of horses arrives in the United States without proper documentation. Currently, when a horse arrives in the United States without proper documentation, that horse remains in quarantine until the proper documents are produced, or the horse is refused entry if the proper documents are not produced. Therefore, the importer incurs additional user fee costs while the horse is held in quarantine, or the importer incurs the cost of shipping the horse back to the country of origin. Therefore, we have determined that the effect on any U.S. entities, large or small, would be insignificant.

Under these circumstances, the Administrator of the Animal and Plant Health Inspection Service has determined that this action would not have a significant economic impact on a substantial number of small entities.

Executive Order 12778

This proposed rule has been reviewed under Executive Order 12778, Civil Justice Reform. If this proposed rule is adopted: (1) All State and local laws and regulations that are inconsistent with this rule will be preempted; (2) no retroactive effect will be given to this rule; and (3) administrative proceedings will not be required before parties may file suit in court challenging this rule.

Paperwork Reduction Act

In accordance with section 3507(d) of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the information

collection or recordkeeping requirements included in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB). Please send written comments to the Office of Information and Regulatory Affairs, OMB, Attention: Desk Officer for APHIS, Washington, DC 20503. Please state that your comments refer to Docket No. 95–053–1. Please send a copy of your comments to: (1) Docket No. 95–053–1, Regulatory Analysis and Development, PPD, APHIS, suite 3C03, 4700 River Road Unit 118, Riverdale, MD 20737–1238, and (2) Clearance Officer, OIRM, USDA, room 404–W, 14th Street and Independence Avenue SW., Washington, DC 20250. A comment to OMB is best assured of having its full effect if OMB receives it within 30 days of publication of this proposed rule.

This proposed rule would require that, upon arrival in the United States, horses travelling through countries of transit en route to the United States be accompanied by either a certification signed by the horses' owner verifying that the horses were not offloaded in any countries of transit or a certification signed by a veterinary officer of the country of transit in which the horses were offloaded that attests to the horses' freedom from evidence of communicable disease when the horse was offloaded and a veterinary inspection was performed in the country of transit. This proposed rule would therefore introduce two new information collection requirements that would enable us to ensure that horses destined for the United States are healthy when they leave their country of origin, remain healthy during their journey, and pose a minimal health risk to the U.S. horse population upon arriving in the United States. We are soliciting comments from the public (as well as affected agencies) concerning our proposed information collection. We need this outside input to help us:

(1) Evaluate whether the proposed information collection is necessary for the proper performance of our agency's functions, including whether the information will have practical utility;

(2) Evaluate the accuracy of our estimate of the burden of the proposed information collection, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the information collection on those who are to respond (such as through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses).

Estimate of burden: Public reporting burden for this collection of information is estimated to average 5 minutes per response.

Respondents: Veterinarians and horse owners.

Estimated number of respondents: 250.

Estimated number of responses per respondent: 1.

Estimated Total Annual Burden on Respondents: 21 hours.

Copies of this information collection can be obtained from the Department of Agriculture, Clearance Officer, OIRM, Ag. Box 7630, Washington, DC 20250.

List of Subjects in 9 CFR Part 92

Animal disease, Imports, Livestock, Poultry and poultry products, Quarantine, Reporting and recordkeeping requirements.

Accordingly, 9 CFR part 92 would be amended as follows:

PART 92—IMPORTATION OF CERTAIN ANIMALS AND POULTRY AND CERTAIN ANIMAL AND POULTRY PRODUCTS; INSPECTION AND OTHER REQUIREMENTS FOR CERTAIN MEANS OF CONVEYANCE AND SHIPPING CONTAINERS THEREON

1. The authority citation for part 92 would continue to read as follows:

Authority: 7 U.S.C. 1622; 19 U.S.C. 1306; 21 U.S.C. 102–105, 111, 114a, 134a, 134b, 134c, 134d, 134f, 135, 136, and 136a; 31 U.S.C. 9701; 7 CFR 2.22,
2.80, and 371.2(d).

2. Section 92.300 would be amended by adding definitions for *Country of origin* and *Country of transit,* in alphabetical order, to read as follows:

§ 92.300 Definitions.

* * * * *

Country of origin. The country in which a horse was born, was raised, and remained until importation to the United States, or the country into which the horse was legally imported and remained for a period of not less than 60 days prior to shipment to the United States.

Country of transit. A country through which a horse travels en route from the country of origin to the United States.

* * * * *

3. Section 92.304 would be amended as follows:

a. In paragraph (a)(1)(i), by revising the second sentence to read as set forth below.

b. At the end of the section, by adding the following: ''(Approved by the Office of Management and Budget under control number 0579–0040)''.

§ 92.304 Import permits for horses from countries affected with CEM, and for horse specimens for diagnostic purposes; [12] and reservation fees for space at quarantine facilities maintained by APHIS.

(a) * * *

(1)(i) * * * The application must specify the name and address of the importer; the species, breed, number or quantity of horses or horse test specimens to be imported; the purpose of the importation; individual horse identification which includes a description of the horse, name, age, markings, if any, registration number, if any, and tattoo or eartag; the country of origin; the name and address of the exporter; the port of embarkation in the foreign country; the route of travel from the country of origin to the United States, including the country of origin, all countries of transit, all modes of transportation, all locations, if any, where the horses will be offloaded, and the port of entry in the United States; the proposed date of arrival of the horses or horse test specimens to be imported; and the name of the person to whom the horses or horse test specimens will be delivered and the location of the place in the United States to which delivery will be made from the port of entry. * * *

* * * * *

4. Section 92.314 would be amended as follows:

a. By designating the existing text as paragraph (a) and by adding a paragraph heading to read ''*General requirements.*''

b. In newly designated paragraph (a), the proviso beginning with ''*And provided, further*'' and the text following it is removed and new text is added in its place to read as set forth below.

c. By adding a new paragraph (b) to read as set forth below.

d. At the end of the section, by adding an OMB control number to read as set forth below.

§ 92.314 Horses, certification, and accompanying equipment.

(a) * * * *And provided, further,* That upon inspecting horses at the port of entry and before permitting them to leave the port of entry, the inspector may require their disinfection and the disinfection of their accompanying equipment as a precautionary measure against the introduction of foot-and-mouth disease or any other disease dangerous to the livestock of the United States.

[12] See footnote 7 to subpart C.

(b) *Special requirements for horses traveling through countries of transit.* In addition to meeting all of the applicable requirements of this subpart, horses shipped to the United States through a country or countries of transit must meet the following conditions:

(1) If a horse intended for importation into the United States will travel through a country or countries of transit but will not be offloaded in the country or countries of transit, then, prior to the horse's shipment from the country of origin, the owner of the horse, or the owner's representative, must certify that the horse will be shipped directly to the United States. The certification must read as follows: ''The horse will be sent directly from the premises of origin to the premises of destination without coming into contact with other equine animals not accompanied by an official health certificate, in vehicles cleaned and disinfected in advance with a disinfectant officially recognized in the country of origin.'' This certification must be signed by the owner of the horse or the owner's representative, and the signed certification must be presented to an inspector at the port of entry in the United States. If, after the certification is signed, an unscheduled offloading of a shipment of horses occurs in a country of transit, then the horses must meet all of the requirements of paragraphs (b)(2) and (b)(3) of this section.

(2) If a horse intended for importation into the United States will travel through a country or countries of transit and will be offloaded in the country or countries of transit, then the horse must be offloaded in a facility that is capable of being cleaned and disinfected and that is approved by the country of transit's Ministry of Agriculture for the offloading of in-transit horses. Within the facility, the horse must be kept separate from all other horses. All horses offloaded in a country or countries of transit must undergo a veterinary inspection and receive a health certificate from a salaried veterinary officer of the national government of each country of transit in which the horse is offloaded. The veterinary inspection must be performed no earlier than 24 hours before the horse is reloaded on a transport vehicle for shipment. If, after performing the inspection, the salaried veterinary officer of the national government of the country of transit finds the horse intended for importation into the United States to be free of evidence of communicable diseases and fit to travel, the veterinary officer must complete the form shown in paragraph (b)(3) of this section.

(3) A completed certificate of inspection, as shown below, must accompany any horse offloaded in a country of transit to the U.S. port of arrival and be produced for the inspector at the port of arrival upon the horse's arrival in the United States.

Certification of Inspection of Import Animals

1. Permit No. _____
2. Consignor's Name (Last name, first name, middle initial or business name) _____
3. Consignor's Street Address (Mailing address) _____
4. Consignor's City/Town _____
5. Consignor's Country _____
6. Consignee's Name (Last name, first name, middle initial or business name) _____
7. Consignee's City/Town _____
8. Consignor's State _____
9. Species of Animals Certified for Import __
10. Country of Origin _____
11. Breed of Animals Certified for Import __
12. Number of Animals Inspected _____
13. Country of Transit/City in Which Inspection Occurred _____
14. Date of Arrival in and Date of Departure from Country of Transit _____
15. Name of Veterinarian Performing Inspection in Country of Transit _____

The animals described on this form have been given a careful veterinary inspection and found to be free from evidence of communicable disease and, in my opinion, fit to travel.

16. Signature of Veterinarian Performing Inspection in Country of Transit _____
17. Date Issued _____
18. Seal _____
19. Remarks _____

(Approved by the Office of Management and Budget under control number 0579–0040)

Done in Washington, DC, this 3rd day of May 1996.

Terry L. Medley,

Acting Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 96–11635 Filed 5–9–96; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Chapter 1

[Docket No. 96N–0094]

Uniform Compliance Date for Food Labeling Regulations; Correction

AGENCY: Food and Drug Administration, HHS.

ACTION: Proposed rule; correction.

SUMMARY: The Food and Drug Administration (FDA) is correcting a proposed rule that appeared in the Federal Register of April 15, 1996 (61 FR 16422). The document proposed to establish January 1, 1998, as its new uniform compliance date for all food labeling regulations that are issued after the publication of a final rule based on the proposal and before January 1, 1997. The document was published with an editorial error. This document corrects that error.

FOR FURTHER INFORMATION CONTACT: Gerad L. McCowin, Center for Food Safety and Applied Nutrition (HFS–150), Food and Drug Administration, 200 C St. SW., Washington, DC 20204, 202–205–4561.

In FR Doc. 96–9319, appearing on page 16422 in the Federal Register of Monday, April 15, 1996, the following correction is made:

1. On page 16422, in the first column, after the ''DATES'' caption, a new caption is added to read as follows: ''ADDRESSES: Submit written comments to the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857.''

Dated: May 6, 1996.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 96–11788 Filed 5–9–96; 8:45 am]

BILLING CODE 4160–01–F

21 CFR Part 328

[Docket No. 95N–0341]

Over-the-Counter Drug Products Intended for Oral Ingestion that Contain Alcohol; Proposed Amendment of Final Rule

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Food and Drug Administration (FDA) is issuing a notice of proposed rulemaking that would amend the regulations for over-the-counter (OTC) drug products intended for oral ingestion that contain alcohol as an inactive ingredient by exempting ipecac syrup from the maximum concentration limits of 0.5 percent alcohol or less when used by children under 6 years of age. This proposal is part of the ongoing review of OTC drug products conducted by FDA.

DATES: Submit written comments by June 10, 1996; written comments on the agency's economic impact determination by June 10, 1996. The agency is proposing that any final rule based on this proposal become effective on the date of its publication in the Federal Register.

ADDRESSES: Submit written comments to the Dockets Management Branch

(HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: William E. Gilbertson, Center for Drug Evaluation and Research (HFD–105), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301–827–2304.

SUPPLEMENTARY INFORMATION:

I. Background

In the Federal Register of March 13, 1995 (60 FR 13590), the agency issued a final rule establishing in § 328.10 (21 CFR 328.10) maximum concentration limits for alcohol (ethyl alcohol) as an inactive ingredient in OTC drug products intended for oral ingestion. The maximum concentration limit was set at 0.5 percent for any OTC drug product labeled for use by children under 6 years of age, and 5 percent for any OTC drug product labeled for use by children 6 to under 12 years of age. The final rule did not discuss ipecac syrup, an OTC drug product used to cause vomiting when poisoning occurs.

The United States Pharmacopeia (USP) 23d Revision states that alcohol is contained in ipecac syrup in concentrations between 1.0 and 2.5 percent (Ref. 1). Alcohol is used in the preparation of the syrup to ensure the complete extraction of alkaloids as their amine salts from ipecac powder and to reject extraneous material when ipecac syrup is prepared by percolation (Ref. 2).

Under § 201.308(c) (21 CFR 201.308(c)), OTC marketing of ipecac syrup is limited to a 1-fluid-ounce (30 milliliters (mL)) package. The product's labeling must contain a statement conspicuously boxed and in red letters that states: ''For emergency use to cause vomiting in poisoning. Before using, call physician, the Poison Control Center, or hospital emergency room immediately for advice.'' The labeling also must state: ''Usual dosage: 1 tablespoon (15 milliliters) in persons over 1 year of age.''

As part of the rulemaking for OTC poison treatment drug products (50 FR 2244, January 15, 1985), the agency proposed a dose of 1 tablespoonful (15 mL or 1/2 bottle) of ipecac syrup for children 1 to under 12 years of age. The agency also proposed a dose of 1 teaspoonful (5 mL) for children 6 months to under 1 year of age, and that ipecac syrup not be given to children under 6 months of age unless directed by a health professional. The agency will finalize these directions for use in a future issue of the Federal Register.

References

(1) United States Pharmacopeia 23d Revision National Formulary 18, United States Pharmacopeial Convention, Inc., Rockville, MD, pp. 834–835, 1994.

(2) ''Solutions Using Mixed Solvent Systems: Spirits, Elixirs, and Extracted Products,'' in *Sprowls' American Pharmacy*, 7th ed., J. B. Lipincott Co., Philadelphia, pp. 100–101, 1974.

II. The Agency's Proposed Amendment

The agency is proposing to exempt ipecac syrup from the requirements of § 328.10(d), which limit alcohol content to 0.5 percent or less in OTC drug products intended for oral ingestion for use by children 6 years of age or less.

Ipecac syrup is indicated for use in potential life-threatening emergencies with directions for use calling for a one-time treatment dose of 15 mL for children 1 to under 12 years of age. Ipecac syrup is usually used under the advice of a health professional, and it is not indicated for repeated or routine use. Because the maximum amount of ipecac syrup per packaged container does not exceed 30 mL, the maximum quantity of alcohol at a 2.5 percent concentration contained in 30 mL of ipecac syrup is 0.75 mL. If a child under 6 years old swallowed the entire contents of a 30 mL container of ipecac syrup, the ingested amount of alcohol (0.75 mL) is insignificant. In addition, the alcohol and the ipecac syrup are generally vomited together with other stomach contents. The agency concludes that the benefit of ipecac syrup as an emetic outweighs any risk of adverse effects from ingestion of 0.75 mL of alcohol. Accordingly, the agency is proposing to add a new paragraph to § 328.10 to state: ''Ipecac syrup is exempt from the provisions of paragraph (d) of this section.'' This means that ipecac syrup may contain more than 0.5 percent alcohol even though labeled for use by children under 6 years of age. The agency is designating this new paragraph as paragraph (f) and redesignating current paragraph (f) as paragraph (g).

III. Analysis of Impacts

The agency has examined the economic consequences of this proposed rulemaking in conjunction with other rules resulting from the OTC drug review. In a notice published in the Federal Register of February 8, 1983 (48 FR 5806), the agency announced the availability of an assessment of these economic impacts. The assessment determined that the combined impacts of all the rules resulting from the OTC drug review do not constitute a major rule according to the criteria established by Executive Order 12291. Executive Order 12291 has been superseded by Executive Order 12866. FDA has examined the impacts of the proposed rule under Executive Order 12866 and the Regulatory Flexibility Act (Pub. L. 96–354). Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity). The agency believes that this proposed rule is consistent with the regulatory philosophy and principles identified in the Executive Order. In addition, the proposed rule is not a significant regulatory action as defined by the Executive Order and, thus, is not subject to review under the Executive Order.

The Regulatory Flexibility Act requires agencies to analyze regulatory options that would minimize any significant impact of a rule on small entities. This proposal has no effect on the OTC marketing of ipecac syrup drug products. Therefore, the agency certifies that this proposal, if implemented, will not have a significant economic impact on a substantial number of small entities.

The agency invites public comment regarding any substantial or significant economic impact that this rulemaking would have on OTC drug products intended for oral ingestion that contain alcohol as an inactive ingredient. Comments regarding the impact of this rulemaking on OTC drug products intended for oral ingestion that contain alcohol as an inactive ingredient should be accompanied by appropriate documentation.

IV. Environmental Impact

The agency has determined under 21 CFR 25.24(c)(6) that this action is not of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

V. Request for Comments

Interested persons may, on or before June 10, 1996, submit to the Dockets Management Branch (address above) written comments or objections on the proposed regulation. Written comments on the agency's economic impact determination may be submitted on or before June 10, 1996. Three copies of all comments or objections are to be submitted, except that individuals may submit one copy. Comments or

objections are to be identified with the docket number found in brackets in the heading of this document and may be accompanied by a supporting memorandum or brief. The agency has determined that comments or objections should be submitted within 30 days because this proposal has no effect on currently marketed products.

List of Subjects in 21 CFR Part 328

Drugs, Labeling, Alcohol.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs, it is proposed that 21 CFR part 328 be amended as follows:

PART 328—OVER-THE-COUNTER DRUG PRODUCTS INTENDED FOR ORAL INGESTION THAT CONTAIN ALCOHOL

1. The authority citation for 21 CFR part 328 continues to read as follows:

Authority: Secs. 201, 301, 501, 502, 503, 505, 701 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 321, 331, 351, 352, 353, 355, 371).

2. Section 328.10 is amended by redesignating paragraph (f) as paragraph (g) and by adding new paragraph (f) to read as follows:

§ 328.10 Alcohol.

* * * * *

(f) Ipecac syrup is exempt from the provisions of paragraph (d) of this section.

* * * * *

Dated: May 1, 1996.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 96–11640 Filed 5–9–96; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Part 3500

[Docket No. FR–3780–N–07]

RIN 2502–AG40

Office of the Assistant Secretary for Housing—Federal Housing Commissioner; Mortgage Broker Fee Disclosure Rule: Notice of Meeting of Negotiated Rulemaking Advisory Committee

AGENCY: Office of the Assistant Secretary for Housing—Federal Housing Commissioner, HUD.

ACTION: Notice of committee meeting.

SUMMARY: The Department has established a Negotiated Rulemaking Advisory Committee to address certain issues concerning indirect payments to mortgage brokers and certain other mortgage originators (retail lenders) and volume-based compensation. The committee, which consists of representatives with a definable stake in the outcome of a proposed rule, has convened on 5 prior occasions in the past 5 months. This notice announces the time and place for the next meeting. This meeting is open to the public.

DATES: The sixth meeting of the committee will be held on May 20–21, 1996. On Monday, May 20, the meeting will start at 9:00 a.m. and will end at 5:00 p.m., and on Tuesday, May 21, the meeting will start at 9:00 a.m. and run until approximately 4:00 p.m.

ADDRESSES: The next meeting of the committee will be held in the Headquarters of the American Association of Retired Persons, 601 ''E'' Street, NW., Room 120, Floor 2–B, Washington, DC.

FOR FURTHER INFORMATION CONTACT: David R. Williamson, Director, Office of Consumer and Regulatory Affairs, Department of Housing and Urban Development, 451 7th Street, SW., Room 5241, Washington, DC 20410–8000); telephone number: (202) 708–4560 (this is not a toll-free number); e-mail through Internet at david—r.—williamson@hud.gov. For hearing- and speech-impaired persons, this number may be accessed via TDD by calling the Federal Information Relay Service at 1–800–877–8339.

SUPPLEMENTARY INFORMATION: On December 8, 1995 (60 FR 63008), HUD published a notice announcing the establishment and first meeting of the Negotiated Rulemaking Advisory Committee on Mortgage Broker Disclosures, to discuss and negotiate a proposed rule on the treatment under RESPA, including disclosure requirements, of payments to retail lenders and of volume-based compensation to mortgage brokers. The committee convened in Washington, DC, on December 13–14, 1995; January 18–19, 1996; February 22–23, 1996; March 18–19, 1996; and April 8–9, 1996. The committee expects that the upcoming meeting on May 20–21 will be the last meeting for this rulemaking effort.

This meeting is open to the public, with limited seating available on a first-come, first-served basis.

Authority: 42 U.S.C. 1437g, 3535(d).

Dated: May 3, 1996.

James E. Schoenberger,

Associate General Deputy Assistant Secretary for Housing Federal Housing Commissioner.

[FR Doc. 96–11648 Filed 5–9–96; 8:45 am]

BILLING CODE 4210–27–U

DEPARTMENT OF THE INTERIOR

National Indian Gaming Commission

25 CFR Part 525

RIN 1076–AD67

Request for Comments on Establishing Departmental Procedures To Authorize Class III Gaming on Indian Lands When a State Raises an Eleventh Amendment Defense To Suit Under the Indian Gaming Regulatory Act

AGENCY: National Indian Gaming Commission, Interior.

ACTION: Advance notice of proposed rulemaking.

SUMMARY: The Department of the Interior seeks comments on its authority under the Indian Gaming Regulatory Act (IGRA), 25 U.S.C. Section 2710, to promulgate ''procedures'' to authorize Class III gaming on Indian lands when a State raises an Eleventh Amendment defense to an action brought against it pursuant to Section ll of the Act, 25 U.S.C. Section 2710(d)(7), and on other related matters. This advance notice is the result of the Supreme Court decision in *Seminole Tribe of Florida* v. *State of Florida,* 116 S.Ct. 1114 (1996).

DATES: Written public comment is invited and will be considered in the development of a proposed rule. Comments on this advance notice of proposed rulemaking must be received no later than July 1, 1996, to be considered.

ADDRESSES: Any comments concerning this notice, including sections regarding conformance with statutory and regulatory authorities, may be sent to: George Skibine, Director, Indian Gaming Management Staff, 1849 C Street, N.W., MS–2070 MIB, Washington, D.C. 20240.

FOR FURTHER INFORMATION CONTACT: George Skibine, Director, Indian Gaming Management Staff, (202) 219–4066.

SUPPLEMENTARY INFORMATION:

Background

Congress enacted IGRA to provide a statutory basis for the operation and regulation of Indian gaming and to protect Indian gaming as a means of generating revenue for tribal governments. 25 U.S.C. Section 2702;

Seminole, at 1119. Since its passage in 1988, more than 140 compacts in more than 20 States have been successfully negotiated, entered into by States and Tribes and approved by the Secretary. Today, Indian gaming is a successful industry generating significant governmental revenue for Indian tribes, which provides funding for essential government services such as roads, schools, and hospitals. Prior to enactment of IGRA, States generally were precluded from any regulation of gaming on Indian reservations. See *California* v. *Cabazon Band of Mission Indians*, 480 U.S. 202 (1987). IGRA, by offering States an opportunity to participate with Indian tribes in developing regulations for Indian gaming, ''extends to States a power withheld from them by the Constitution.'' *Seminole*, at 1124.

IGRA requires an Indian Tribe that wants to conduct casino type (''Class III'') gaming on its Indian lands to negotiate a ''compact'' of terms and conditions for such gaming with the State in which the Indian lands are located. IGRA also provides that if the State fails to bargain, or to do so in good faith, the Tribe may sue the State in Federal court to enforce the remedial provisions provided by the statute. Under these provisions, if a court found a State not to be bargaining in good faith, it would ''order the State and the Indian Tribe to conclude such a compact within a 60-day period.'' 25 U.S.C. Section 2710(d)(7)(B)(iii). If thereafter a State and Tribe fail to conclude a compact within this 60-day period, they ''shall each submit to a mediator appointed by the court a proposed compact that represents their last best offer for a compact.'' *Id.* Section 2710(d)(7)(B)(iv). The mediator shall then ''select from the two proposed compacts the one which best comports with the terms of this Act and any other applicable Federal law and with the findings and order of the court,'' id., and submit his or her selection to the State and Tribe, *id.* Section 2710(d)(7)(B)(v). If, within 60 days from the mediator's submission of his or her selection, the State consents to a proposed compact, such a compact authorizes Indian gaming pursuant to IGRA. *Id.*

Section 2710(d)(7)(B)(vi). If the State does not consent to a compact within 60 days of the mediator's submission, the Secretary of the Interior shall:

prescribe, in consultation with the Indian tribe, procedures—

(I) which are consistent with the proposed compact selected by the mediator under [25 U.S.C. Section 2710(d)(7)(B)(iv)], the provisions of [the Act] and the relevant provisions of the laws of the State, and

(II) under which class III gaming may be conducted on the Indian lands over which the Indian tribe has jurisdiction.

25 U.S.C. Section 2710(d)(7)(B)(vii). In practice, only a handful of cases have required resort to IGRA's judicial enforcement mechanism.

In *Seminole Tribe of Florida* v. *Florida*, the Supreme Court affirmed a decision by the Eleventh Circuit Court of Appeals holding that Congress may not abrogate State Eleventh Amendment immunity under the Indian Commerce Clause. The decision raises questions about the process now to be followed by Tribes who cannot secure State cooperation in the compacting process.

The Supreme Court's *Seminole* decision does not affect the validity of existing class III gaming compacts, but it does require the United States to consider the effect of a State's refusal to engage in remedial litigation designed to oversee the compacting process. In its decision below, the Eleventh Circuit suggested that the compacting process could proceed as prescribed by IGRA (including litigation) so long as a State did not assert its Eleventh Amendment immunity. In light of IGRA's severability clause, the Eleventh Circuit further expressed the view that if a State pleads an Eleventh Amendment defense and the suit is dismissed, the Tribe may then notify the Secretary and the Secretary may prescribe the terms of the particular compact. The Supreme Court expressly declined to consider the validity of this part of the Eleventh Circuit's opinion, and Florida's cross-petition for review of this issue was denied by the Supreme Court. By contrast, the Ninth Circuit, in its pre-*Seminole* decision rejecting an Eleventh Amendment challenge, *Spokane Tribe of Indians* v. *Washington*, 28 F.3d 991 (9th Cir. 1994), expressed disagreement with the Eleventh Circuit's views on that issue. *Id.* at 997.

In these circumstances, and because of the importance of the issues to the Tribes, the States, and the general public, the Department seeks comments regarding the manner in which the compacting provisions of IGRA may operate following the Supreme Court's *Seminole Tribe* decision.

Subject Matter of Potential Rulemaking

The Department seeks comments on the following specific issues, and on other issues directly related to the subject matter of this notice.

(1) The effect of the Supreme Court's decision in *Seminole Tribe* on the operation of other provisions in 25 U.S.C. Section 2710(d)(7) when a State does not waive its Eleventh Amendment immunity to suit;

(2) Whether, and under what circumstances, the Secretary of the Interior is empowered to prescribe ''procedures'' for the conduct of Class III gaming when a State interposes an Eleventh Amendment defense to an action pursuant to 25 U.S.C. Section 2710(d)(7)(B);

(3) What is an appropriate administrative process for the development of Secretarial procedures;

(4) What procedures should be followed if a State interposes an Eleventh Amendment defense to an action filed under 25 U.S.C. Section 2710(d)(7)(B);

(5) What procedures can be, and should be, utilized for determining legal issues that may be in dispute, such as the ''scope of gaming'' permitted under State law. The scope of gaming issue arises when a State takes the position that it is not required to bargain with a Tribe with respect to certain Class III games because IGRA does not authorize such games on the ground that such games are not permitted by the State ''for any purpose by any person,'' *see* 25 U.S.C. Section 2710(d)(1)(B)1; and

(6) How any procedures promulgated by the Secretary may, and should, provide for appropriate regulation of Indian gaming.

Public Review

Comments on this notice may be submitted in writing to the address identified at the beginning of this rulemaking by July 1, 1996. Comments received by that date will be considered in the development of any proposed rule.

Executive Order 12866

This advance notice of proposed rulemaking has been reviewed by the Office of Management and Budget under Executive Order 12866.

Drafting Information

This Notice was drafted by the Office of the Solicitor, 1849 C Street, N.W., Washington, D.C., 20240.

Dated: April 30, 1996.

Ada E. Deer,

Assistant Secretary, Indian Affairs.

[FR Doc. 96–11287 Filed 5–9–96; 8:45 am]

BILLING CODE 4210–02–P

DEPARTMENT OF JUSTICE

Federal Bureau of Investigation

28 CFR Part 100

RIN 1105–AA39

Implementation of Section 109 of the Communications Assistance for Law Enforcement Act

AGENCY: Federal Bureau of Investigation, DOJ.

ACTION: Proposed rule.

SUMMARY: This rule establishes the procedures whereby telecommunications carriers can recover the costs associated with complying with the Communications Assistance for Law Enforcement Act (CALEA), which requires telecommunications carriers to ensure law enforcement's ability, pursuant to court order or other lawful authorization, to intercept communications notwithstanding advanced telecommunications technologies.

DATES: Written comments must be received on or before July 9, 1996.

ADDRESSES: Comments should be submitted in triplicate to the Telecommunications Contracts and Audit Unit, Federal Bureau of Investigation, P.O. Box 221286, Chantilly, VA 22022–1286, Attention: CALEA FR Representative, telephone number (703) 814–4900.

FOR FURTHER INFORMATION CONTACT: Walter V. Meslar, Unit Chief, Telecommunications Contracts and Audit Unit, Federal Bureau of Investigation, P.O. Box 221286, Chantilly, VA 22022–1286, telephone number (703) 814–4900.

SUPPLEMENTARY INFORMATION: Recent and continuing advances in telecommunications technology and the introduction of new digitally-based services and features have, in some instances, impaired the ability of federal, state, and local law enforcement agencies to fully and properly conduct various types of court-authorized electronic surveillance. Therefore, on October 25, 1994, the President signed into law the Communications Assistance for Law Enforcement Act (CALEA) (Public Law 103–414, 47 U.S.C. 1001–1010). This law requires telecommunications carriers, as defined in CALEA, to ensure law enforcement's ability, pursuant to court order or other lawful authorization, to intercept communications notwithstanding advanced telecommunications technologies.

Under CALEA, certain implementation responsibilities are conferred upon the Attorney General; the Attorney General has, in turn, delegated responsibilities set forth in CALEA to the Director, FBI, or his designee, pursuant to 28 CFR 0.85(o). The Director, FBI, has designated personnel in the Engineering Section of the Information Resources Division and the Property Procurement and Management Section of the Finance Division to carry out these responsibilities.

Definition of ''Telecommunications Carrier''

CALEA defines a ''telecommunications carrier'' as any ''person or entity engaged in the transmission or switching of wire or electronic communications as a common carrier for hire'' (section 102(8)(A)), and includes any ''person or entity engaged in providing commercial mobile service, (as defined in section 332(d) of the Communication Act of 1934, as amended (47 U.S.C. 332(d))'' (section 102(8)(B)). This definition includes, but is not limited to, local exchange and interexchange carriers; competitive access providers; resellers, cable operators, utilities, and shared tenant services providers, to the extent that they offer telecommunications services as common carriers for hire; cellular telephone companies; personal communications services (PCS) providers; satellite-based mobile communications providers; specialized mobile radio services (SMRS) providers and enhanced SMRS providers; and paging service providers.

The Federal Communications Commission (FCC) may determine that a person or entity who is not a common carrier is subject to CALEA if that person or entity provides wire or electronic communication service and the FCC concludes that such service is a replacement for a substantial portion of the local telephone exchange service and that it is in the public interest to deem such a person or entity to be a telecommunications carrier for purposes of CALEA.

The definition does not include (1) persons or entities insofar as they are engaged in providing information services such as electronic publishing and messaging services; and (2) any class or category of telecommunications carriers that the FCC exempts by rule after consultation with the Attorney General.

Capability Requirements

CALEA requires telecommunications carriers to ensure that, within four years of the date of enactment, their systems have the capability to meet the Assistance Capability Requirements as described in section 103 of CALEA. These requirements are that a telecommunications carrier shall ensure that its equipment, facilities, or services that provide a customer or subscriber with the ability to originate, terminate, or direct communications are capable of—

(1) expeditiously isolating and enabling the government, pursuant to a court order or other lawful authorization, to intercept, to the exclusion of any other communications, all wire and electronic communications carried by the carrier within a service area to or from equipment, facilities, or services of a subscriber of such carrier concurrently with their transmission to or from the subscriber's equipment, facility, or service, or at such later time as may be acceptable to the government;

(2) expeditiously isolating and enabling the government, pursuant to a court order or other lawful authorization, to access call-identifying information that is reasonably available to the carrier—(A) before, during, or immediately after the transmission of a wire or electronic communications (or at such later time as may be acceptable to the government); and (B) in a manner that allows it to be associated with the communication to which it pertains, except that, with regard to information acquired solely pursuant to the authority for pen registers and trap and trace devices (as defined in section 3127 of Title 18, United States Code), such call-identifying information shall not include any information that may disclose the physical location of the subscriber (except to the extent that the location may be determined from the telephone number);

(3) delivering intercepted communications and call-identifying information to the government, pursuant to a court order or lawful authorization, in a format such that they may be transmitted by means of equipment, facilities, or services procured by the government to a location other than the premises of the carrier; and

(4) facilitating authorized communication interceptions and access to call-identifying information unobtrusively and with a minimum of interference with any subscriber's telecommunications service and in a manner that protects—(A) the privacy and security of communications and call-identifying information not authorized to be intercepted; and (B) information regarding the government's interception of communications and access to call-identifying information.

Under section 107(a)(2) of CALEA, a carrier will be deemed to be in compliance if it adheres to publicly available technical requirements, feature descriptions, or standards adopted by an industry association or standard-setting organization relevant to CALEA. Telecommunications carriers may also develop their own solutions. In any case, carriers must meet the requirements set forth in Section 103 of CALEA. If no technical requirements or standards are issued, or if they are challenged as being deficient, upon petition, the FCC has authority to develop them through a rule making.

Capacity Requirements

Section 104 of CALEA requires that the Attorney General, after seeking public notice and comment, establish and publish:

(1) Notice of the actual number of communications interceptions, pen registers, and trap and trace devices representing a portion of the maximum capacity required to accommodate all of the communication interceptions, pen registers, and trap and trace devices that the Attorney General estimates that the government agencies authorized to conduct electronic surveillance may conduct and use simultaneously by the date 4 years after the date of enactment of CALEA, and

(2) Notice of the maximum capacity required to accommodate all of the communication interceptions, pen registers, and trap and trace devices that the Attorney General estimates that the government agencies authorized to conduct electronic surveillance may conduct and use simultaneously after the date that is 4 years after the date of enactment of CALEA.

On October 16, 1995 the FBI proposed for comment those notices (60 FR 53643), and on November 9, 1995 the comment period was extended until January 16, 1996.

Section 104 of CALEA also provides that within 180 days after the publication of the final notice of capacity requirements, a telecommunications carrier shall submit to the Attorney General a statement identifying any of the systems or services that do not have the capacity to accommodate simultaneously the number of interceptions, pen registers, and trap and trace devices set forth in that notice. The FBI intends to use those statements as a basis from which to solicit cooperative agreements to reimburse carriers for reasonable costs of modifications performed to comply with CALEA capability and capacity requirements, based on available funding.

Industry Implementation

Industry's compliance with the requirements set forth in section 103 of CALEA is affected by a number of interrelated factors, including whether the Attorney General is required to, and has agreed to, pay for needed modifications, and whether the equipment, facility, or service was installed or deployed on or before January 1, 1995.

In the case of equipment, facilities, and services installed or deployed after January 1, 1995, compliance is dependant upon whether the necessary modifications are reasonably achievable as determined by the FCC using criteria set forth in CALEA. These criteria are as follows:

(1) The effect on public safety and national security.

(2) The effect on rates for basic residential telephone service.

(3) The need to protect the privacy and security of communications not authorized to be intercepted.

(4) The need to achieve the capability assistance requirements of section 103 of CALEA by cost effective methods.

(5) The effect on the nature and cost of the equipment, facility or service at issue.

(6) The effect on the operation of the equipment, facility, or service at issue.

(7) The policy of the United States to encourage the provision of new technologies and services to the public.

(8) The financial resources of the telecommunications carrier.

(9) The effect on competition in the provision of telecommunications services.

(10) The extent to which the design and development of the equipment, facility, or service was initiated before January 1, 1995.

(11) Such other factors as the FCC determines are appropriate.

Telecommunications carriers also may petition regulatory authorities to adjust charges, practices, classifications, and regulations to recover costs expended for making needed modifications to equipment, facilities, or services pursuant to the assistance capability requirements of CALEA section 103. CALEA also includes provisions for exemption, extension of the compliance date, consultation with industry, and systems security. Noncompliance may lead to civil actions by the Attorney General and the imposition of civil fines. In addition, it requires telecommunications transmission and switching equipment manufacturers, as well as providers of telecommunications support services, to cooperate with telecommunications carriers in achieving the required capacities and capabilities.

Section 109 of CALEA, Payment of Costs of Telecommunications Carriers to Comply with Capability Requirements, authorizes the Attorney General, subject to the availability of appropriations, to agree to pay telecommunications carriers for: (1) all reasonable costs directly associated with the modifications performed by carriers in connection with equipment, facilities, and services installed or deployed on or before January 1, 1995, to establish the capabilities necessary to comply with section 103 of CALEA; (2) additional reasonable costs directly associated with making the assistance capability requirements found in section 103 of CALEA reasonably achievable with respect to equipment, facilities, or services installed or deployed after January 1, 1995, in accordance with the procedures established in CALEA section 109(b); and, (3) reasonable costs directly associated with modifications of any of a carrier's systems or services, as identified in the Carrier Statement required by CALEA section 104(d), which do not have the capacity to accommodate simultaneously the number of interceptions, pen registers, and trap and trace devices set forth in the Capacity Notice(s) published in accordance with CALEA section 104.

CALEA section 109(e), Cost Control Regulations, authorizes the Attorney General, after notice and comment, to establish regulations necessary to effectuate timely and cost-efficient payment to telecommunications carriers under CALEA, under 18 U.S.C. chapters 119 and 121 and under the Foreign Intelligence Surveillance Act of 1978 (50 U.S.C. 1801 *et seq.*).

CALEA directs the Attorney General to consult with the FCC prior to the establishment of regulations that will allow for cost recovery by telecommunications carriers of reasonable costs incurred for compliancy.

Regulations shall minimize the cost to the Federal Government and permit recovery by telecommunications carriers of the direct costs of developing necessary modifications for CALEA compliance, including providing the capabilities requested, providing capacities requested, the costs of training personnel in the use of such capabilities and capacities, and the direct costs of deploying or installing such capabilities and capacities.

In the case of any modification that may be used for any purpose other than lawfully authorized electronic surveillance by a law enforcement agency of a government, CALEA permits

the recovery of only the incremental cost of making the modification suitable for such law enforcement purposes.

Establishment of Cost Recovery Rules and Procedures

The regulations proposed herein are intended to ensure that each carrier's practices used in estimating costs are consistent with the current cost accumulating and reporting procedures utilized by the carrier for the preparation of its financial statements. Further, these regulations establish that not all expenses reportable in accordance with generally accepted accounting principles will be eligible for reimbursement. Consistency in the application of cost accounting practices is necessary to enhance the likelihood that comparable transactions are treated alike. Consistent application of internal cost accounting practices will facilitate the preparation of reliable cost estimates and allow comparison with the costs of performance. Such comparisons provide an important basis for financial control over costs and aid in establishing accountability for cost in the manner agreed to by both parties.

These regulations also ensure that each cost is allocated only once and on only one basis to a cost group. The criteria for determining the allocation of costs to a cost group should be the same for all similar groupings.

The following proposed cost recovery rules will be incorporated in any cooperative agreement established under section 109 of CALEA and entered into between the carriers and the FBI. Subsequent to the submission to the FBI of the Carrier Statements, as required under section 104(d) of CALEA, the FBI will directly solicit cooperative agreements from the carriers based upon available funding. A separate Federal Register notice concerning carrier statements will be published soon. These rules were developed to establish the procedures whereby carriers may seek reimbursement under section 109(a) and 104(e) of CALEA. Cost recovery under section 109(b)(2) of CALEA will be determined pursuant to the procedures set forth in section 109(b)(1) of CALEA in accordance with these cost recovery rules as promulgated. To the extent possible, these rules will allow carriers to utilize their existing accounting procedures to record the costs of bringing equipment, facilities, and services into compliance with CALEA.

Applicable Administrative Procedures and Executive Orders

Regulatory Flexibility Act

As required by section 603 of the Regulatory Flexibility Act, the FBI has prepared this Initial Regulatory Flexibility Analysis (IRFA) section to ascertain the expected impact on small entities of the regulations proposed in this document. The FBI is obligated to implement the mandate of Congress as set out in CALEA. Therefore, these regulations were developed to establish the mechanism whereby telecommunications carriers can recover the costs associated with complying with CALEA. The FBI seek to subject all carriers to the same regulatory policy (proposed herein), while allowing carriers to utilize their existing accounting systems in the reimbursement process. Pursuant to the goal of imposing the least burden on carriers while also fulfilling the obligation to adhere to Government fiscal accountability requirements, the proposed regulations specify reporting objectives rather than specifying the manner in which these records must be kept. The FBI estimates that approximately three thousand (3,000) telecommunications carriers may be affected by these rules. While most carriers are not large in terms of capitalization, most are dominant within their markets, so they are not considered ''small'' for the purposes of the Regulatory Flexibility Act. Although it is not anticipated that any small carriers will be adversely affected, these proposed rules have been written to allow any such carriers to seek reimbursement in an equitable manner. Therefore, these regulations seek to allow these carriers to use their current recordkeeping procedures, along with the existing skill levels on their staffs. As mandated by section 603(c) of the Regulatory Flexibility Act, consideration was given to alternative forms of compliance requirements for the small entities affected by these proposed rules. However, the FBI determined that these alternatives were not viable in that they would require the carriers to alter their internal accounting methodologies, would not take into account carrier individuality with respect to directly allocable costs or would violate CALEA's mandate to reimburse carriers' reasonable costs, while maintaining Government fiscal accountability requirements. This Proposed Rule solicits comments on both the proposed regulations and their possible impact on small entities. The FBI will send a copy of these proposed rules, including this IRFA, to the Chief Counsel for Advocacy of the Small Business Administration in accordance with section 603(a) of the Regulatory Flexibility Act, Public Law 96–354, 94 Stat. 1164, 5 U.S.C. 601 *et seq.* There are no federal rules that overlap, duplicate or conflict with these rules.

Executive Order 12612

These regulations will not have substantial direct effects on the States, on the relationship between the national Government and the States, or on distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

Executive Order 12866

The FBI has examined these proposed regulations in light of Executive Order 12866 and has found that they constitute a significant regulatory action under sections 3(f)(1) and 3(f)(4). Pursuant to Executive Order 12866, 28 CFR part 100 is the draft text of the regulatory actions that are required under CALEA. These proposed regulations promulgate procedures whereby carriers may seek reimbursement for their efforts to assist law enforcement in preserving electronic surveillance capabilities as mandated by CALEA, which authorizes appropriations of $500 million for carrier reimbursement. These regulations have been developed in order to effect the least burden on the administrative staffs of both the carriers and the Government while maintaining the Government's obligation to adhere to its fiscal accountability requirements. In order to accomplish this goal, the proposed regulations specify reporting objectives rather than specifying the manner in which these records must be kept. As mandated by Executive Order 12866, consideration was given to potentially effective and feasible alternatives to the proposed regulations. However, the FBI determined that alternative requirements were not viable in that they would require the carriers to alter their internal accounting methodologies, would not take into account carrier individuaity with respect to directly allocable costs and violate CALEA's mandate to maintain Government fiscal accountability standards in the reimbursement process.

Unfunded Mandates Reform Act of 1995

As required by Title II of the Unfunded Mandates Reform Act of 1995, this section assesses the effects of

the proposed regulations on State, local and tribal governments and the private sector. These regulations are required under section 109(e) of CALEA. No unfunded mandate is imposed upon State, and local or tribal governments by these regulations. Therefore, sections 203 and 204 of the Unfunded Mandates Reform Act do not apply to these proposed rules. However, the FBI has determined that these proposed rules are subject to sections 201, 202, and 205 of the Unfunded Mandates Reform Act. While the telecommunications industry is primarily affected by these proposed rules, all reasonable costs, as shall be defined in 28 CFR part 100, incurred by the private sector will be subject to reimbursement from the $500 million authorized to be appropriated by Congress under CALEA section 110. Furthermore, CALEA sections 109 and 104 specifically establish the conditions whereby a telecommunications carrier may be deemed in compliance with regard to the equipment, facilities or services covered in these proposed regulations should the Government not agree to reimburse the carrier for the compliance effort. Accurate estimates of the effects on the national economy of this part, which is proposed so that carriers may seek reimbursement for their efforts to assist law enforcement in preserving electronic surveillance capabilities as mandated by CALEA, are not feasible. As mandated by section 205 of the Unfunded Mandates Reform Act, consideration was given to potentially effective and feasible alternates to the proposed rules. However, the FBI determined that alternative requirements were not viable in that they would require the carriers to alter their internal accounting methodologies, would not take into account carrier individuality with respect to directly allocable costs and violated CALEA's mandate to maintain Government fiscal accountability standards in the reimbursement process.

Information Collection Under Review

The proposed information collection is published to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted for sixty days from the date listed at the top of this page in the Federal Register. This process is conducted in accordance with the Paperwork Reduction Act of 1995.

This collection covers:

(1) Type of Information Collection: NEW COLLECTION: Quantitative and qualitative data necessary to evaluate cooperative agreement proposals and subsequent requests for reimbursement.

(2) The title of the information collection: ''Telecommunications Carrier Reimbursement Cost Estimate'' and ''Telecommunications Carrier Reimbursement Request for Payment.''

(3) The agency form number, if any, and the applicable component of the Department sponsoring the collections: No form number; sponsored by the FBI, United States Department of Justice.

(4) Who will be asked or required to respond, as well as a brief abstract; BUSINESS OR OTHER FOR PROFIT: Telecommunications carriers will respond. This data collection will be necessary to evaluate cooperative agreement proposals and subsequent requests for reimbursement under CALEA. This information will be used to determine whether agreement prices are fair and reasonable and to make recommendations to agreement officers for approval or disapproval of the carrier's request.

(5) An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond: The FBI estimates that approximately three thousand (3,000) telecommunications carriers, with approximately twenty-three thousand (23,000) unique switches, that, over a five (5) year period, may be affected by these rules. The time required to read and prepare information for one switch is estimated at four (4) hours per response.

By publication of this notice, written comments and suggestions from the public and affected agencies concerning the proposed collection of information was requested. Your comments should address one or more of the following four points:

(1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical or other technological collection techniques or other forms of information technology (i.e., permitting electronic submission of responses).

Comments or suggestions regarding the items contained in this information collections request should be directed to Mr. Porter F. Dunn, Telecommunications Contracts and Audit Unit, Federal Bureau of Investigation, P.O. Box 221286, Chantilly, VA 22022–1286, telephone number (703) 814–4902.

List of Subjects in 28 CFR Part 100

Accounting, Law enforcement—wiretapping and electronic surveillance, Reporting and recordkeeping requirements, Telecommunications.

Dated: May 6, 1996.

Louis Freeh,

Director, Federal Bureau of Investigation, Department of Justice.

For the reasons set out in the preamble, 28 CFR part 100 is proposed to be added as follows:

PART 100—COST RECOVERY REGULATIONS, COMMUNICATIONS ASSISTANCE FOR LAW ENFORCEMENT ACT OF 1994

Sec.
100.9 General.
100.10 Definitions.
100.11 Allowable costs.
100.12 Reasonable costs.
100.13 Directly assignable costs.
100.14 Directly allocable costs.
100.15 Disallowed costs.
100.16 Cost estimate submission.
100.17 Request for payment.
100.18 Audit.
100.19 Reduction for defective cost data.
100.20 Accounting for unallowable costs.
100.21 Confidentiality of trade secrets/proprietary information.

Authority: 47 U.S.C. 1001–1010; 28 CFR 0.85(o).

§ 100.9 General.

These Cost Recovery Regulations were developed to define allowable costs and establish reimbursement procedures in accordance with section 109(e) of Communications Assistance for Law Enforcement Act (CALEA) (Public Law 103–414, 47 U.S.C. 1001–1010). Reimbursement of costs is subject to the availability of funds and agreement, prior to the incurrence of costs, by the Attorney General or designee to reimburse costs.

§ 100.10 Definitions.

(a) *Allocable* means chargeable to two or more costs objectives.

(b) *Business unit* means any segment of an organization for which cost data are routinely accumulated by the carrier for tracking and measurement purposes.

(c) *Cost objective* means a function, organizational subdivision, contract, or other work unit for which cost data are desired and for which provision is made to accumulate and measure the cost of processes, products, jobs, capitalization projects, etc.

(d) *Cost pool* means groupings of incurred costs identified with two or more cost objectives, but not identified specifically with any final cost objective.

(e) *Directly allocable costs* means any costs that are directly chargeable to two or more cost objectives.

(f) *Directly assignable cost* means any cost that can wholly be attributed to a cost objective.

(g) *Directly associated cost* means any directly assignable cost or directly allocable cost which is generated solely as a result of incurring another cost, and which would not have been incurred had the said cost not been incurred.

(h) *Final cost objective* means a cost objective that has allocated to it, both assignable and allocable costs and, in the carrier's accumulation system, is one of the final accumulation points.

(i) *Installed or deployed* means that, on a specific switching system, equipment, facilities, or services are operable and available for use by the carrier's customers.

(j) *Plant nonspecific costs* means costs related to property held for future telecommunications use, along with the associated provisioning expenses, network operations expenses, and depreciation and amortization expenses. These costs shall also include the costs of supervising and office support of these activities.

(k) *Plant specific costs* means costs related to specific kinds of telecommunications plants. These costs shall include the costs of inspecting, testing and reporting on the condition of telecommunications plant to determine the need for repairs, replacements, rearranges and changes; performing routine work to prevent trouble except replacing items of plant other than retirement units; rearranging and changing the location of plant not retired; repairing material for reuse; restoring the condition of plant damaged by storms, floods, fire, or other casualties (other than the cost of replacing retirement units); inspecting after repairs have been made; and receiving training to perform these kinds of work. Also included are the costs of direct supervision (immediate or first-level) and office support of this work.

(l) *Trade secrets/proprietary information* means information which is in the possession of a carrier but not generally available to the public, which that carrier desires to protect against unrestricted disclosure or competitive use, and which is clearly identified as such at the time of its disclosure to the government.

§ 100.11 Allowable costs.

(a) Costs that are eligible for reimbursement under section 109(e) CALEA are:

(1) All reasonable plant specific costs directly associated with the modifications performed by carriers in connection with equipment, facilities, and services installed or deployed on or before January 1, 1995, to establish the capabilities necessary to comply with section 103 of CALEA, until the equipment, facility, or service is replaced or significantly upgraded or otherwise undergoes major modifications;

(2) Additional reasonable plant specific costs directly associated with making the assistance capability requirements found in section 103 of CALEA reasonably achievable with respect to equipment, facilities, or services installed or deployed after January 1, 1995, in accordance with the procedures established in CALEA section 109(b); and

(3) Reasonable plant specific costs directly associated with modifications to any of a carrier's systems or services, as identified in the Carrier Statement required by CALEA section 104(d), that do not have the capacity to accommodate simultaneously the number of interceptions, pen registers, and trap and trace devices set forth in the Capacity Notice(s) published in accordance with CALEA section 104.

(b) Allowable plant specific costs shall include:

(1) The costs of installation, inspection, and testing of the telecommunications plant, and inspection after modifications have been made; and

(2) The costs of direct first-line supervision and office support for this work for plant specific expenses.

(c) In the case of any modification that may be used for any purpose other than lawfully authorized electronic surveillance by a government law enforcement agency, this part permits recovery of only the incremental cost of making the modification suitable for such law enforcement purposes.

(d) Reasonable costs that are directly associated with the modifications performed by a carrier as described in § 100.11(a) are recoverable. These allowable costs are limited to direct and directly allocable costs incurred by the business units whose efforts are expended on the implementation of CALEA requirements.

§ 100.12 Reasonable costs.

(a) A cost is reasonable if, in its nature and amount, it does not exceed that which would be incurred by a prudent person in the conduct of competitive business. Reasonableness of specific costs must be examined with particular care in connection with the carrier or its separate divisions that may not be subject to effective competitive restraints.

(1) No presumption of reasonableness shall be attached to the incurrence of costs by a carrier.

(2) The burden of proof shall be upon the carrier to justify that such cost is reasonable under this part.

(b) Reasonableness depends upon considerations and circumstances, including, but not limited to:

(1) Whether a cost is of the type generally recognized as ordinary and necessary for the conduct of the carrier's business or the performance of this obligation; or

(2) Whether it is a generally accepted sound business practice, arm's-length bargaining or the result of Federal or State laws and/or regulations.

(c) It is the carrier's responsibility to inform the Government of any deviation from the carrier's established practices.

§ 100.13 Directly assignable costs.

(a) An allowable directly assignable cost is any plant specific cost that can be definitively linked with the performance of bringing equipment, facilities or services into compliance with CALEA as described in § 100.11(a).

(1) A direct cost which has been incurred for the same purpose in like circumstances and which has been included in any allocable cost pool to be assigned to that or any other final cost objective shall not be assigned to the CALEA compliance effort (or any portion thereof).

(2) Costs identified specifically with the work performed are direct costs to be charged directly to the CALEA compliance effort. All costs specifically identified with other projects, business units, or cost objectives of the carrier as direct costs shall not be charged to the CALEA compliance effort, directly or indirectly.

(3) The burden of proof shall be upon the carrier to justify that such cost is a direct cost under this part.

(b) For reasons of practicality, any directly assignable cost of minor dollar amount may be treated as a directly allocable cost if the accounting treatment is consistently applied within the carrier's accounting system and the application produces substantially the same results as treating the cost as a directly assignable cost.

§ 100.14 Directly allocable costs.

(a) A cost is directly allocable to the CALEA compliance effort if:

(1) It is plant specific cost incurred specifically to meet the requirements of CALEA sections 103 and 104; or

(2) It benefits both the CALEA compliance effort and other work, and can be distributed to them in reasonable proportion to the benefits received.

(b) The burden of proof shall be upon the carrier to justify that such cost is an allocable cost under this part.

(c) An allocable cost shall not be assigned to the CALEA compliance effort if other costs incurred for the same purpose in like circumstances have been included as a direct cost of that, or any other, cost objective.

(d) The accumulation of allocable costs shall be as follows:

(1) Allocable costs shall be accumulated by logical groupings with due consideration of the reason for incurring such costs.

(i) Each grouping should be determined so as to permit distribution of the grouping on the basis of the benefits accruing to the multiple cost objectives.

(ii) Similarly, the particular case may require subdivision of these groupings (e.g., building occupancy costs might be separable from those of personnel administration within the engineering group).

(2) Such allocation necessitates selecting a distribution base common to all cost objectives to which the grouping is to be allocated. The base should be selected so as to permit allocation of the grouging on the basis of the benefits accruing to the multiple objectives.

(3) When substantially the same results can be achieved through less precise methods, the number and composition of cost groupings should be governed by practical considerations and should not unduly complicate the allocation.

(4) Once a methodology for determining an appropriate base for distributing allocable costs has been accepted by the FBI, it shall not be modified without written approval of the FBI. All items properly includable in an allocable cost base should bear a pro rata share of allocable costs irrespective of their acceptance as reimbursable under this part.

(5) The carrier's method of allocating allocable costs shall be in accordance with the accounting principles used by the carrier in the preparation of their externally audited financial statements and consistently applied, to the extent that the expenses are allowable under these regulations. The method may require further examination when:

(i) Substantial differences occur between the cost patterns of work under CALERA compliance effort and the carrier's other work;

(ii) Significant changes occur in the nature of the business, the extent of subcontracting, fixed-asset improvement programs, inventories, the volume of sales and production, manufacturing processes, the carrier's products, or other relevant circumstances; or

(iii) Allocable cost groupings developed for a carrier's primary location are applied to off-site locations. Separate cost groupings for costs allocable to off-site location may be necessary to permit equitable distribution of costs on the basis of the benefits accruing to the multiple cost objectives.

(6) The base period for allocating allocable costs is the cost accounting period during which such costs are incurred and accumulated for distribution to work performed in that period. The base period for allocating allocable costs will normally be the carrier's fiscal year. A shorter period may be appropriated when performance involves only a minor portion of the fiscal year, or when it is general practice to use a shorter period. When the compliance effort is performed over an extended period, as many base periods shall be used as are required to accurately represent the period of performance.

§ 100.15 Disallowed costs.

(a) General and Administrative (G&A) costs are disallowed. G&A costs include, but are not limited to, any management, financial, and other expenditures which are incurred by or allocated to a business unit and which are for the general management and administration of the business unit as a whole. These include, but are not limited to:

(1) Accounting and Finance, External Relations, Human Resources, Information Management, Legal, Procurement; and

(2) Other general administrative activities such as library services, food services, archives, and general security investigation services.

(b) Customer Service costs are disallowed. These costs include, but are not limited to, any Marketing, Sales, Product Management, and Advertising expenses.

(c) Plant nonspecific costs are disallowed. These include, but are not limited to, expenses related to property held for future telecommunications use, provisioning expenses, network operations expenses, and depreciation and amortization expenses. Any plant nonspecific supervision and office support costs are also disallowed.

(d) Cost that have already been recovered from any governmental or nongovernmental entity are disallowed.

(e) Costs that cannot be either directly assigned or directly allocated are disallowed.

(f) Additional costs that are incurred due to the carrier's failure to complete the CALEA compliance effort in the agreed upon time frame are disallowed.

(g) Costs associated with modifications of any equipment, facility or service installed or deployed after January 1, 1995 which are deemed reasonably achievable by the Federal Communications Commission under section 109(b) of CALEA are disallowed.

§ 100.16 Cost estimate submission.

(a) The carrier shall provide sufficient cost data at the time of proposal submission to allow adequate analysis and evaluation of the estimated costs. The FBI reserves the right to request additional cost data from carriers in order to ensure compliance with this part.

(b) The requirement for submission of cost data is met if, as determined by the FBI, all cost data reasonably available to the carrier are either submitted or identified in writing by the time of agreement.

(c) If cost data and information to explain the estimating process are required by the FBI and the carrier refuses to provide necessary data, or the FBI determines that the data provided are so deficient as to preclude adequate analysis and evaluation, the FBI will attempt to secure the data and/or elicit corrective action. If the carrier persists in refusing to provide the needed data or to take corrective action, the FBI will refer the action to higher authority, including details of the attempts made to resolve the matter, and a statement of noncompliance with CALEA will be issued.

(d) Instructions for submission of the cost data for the estimate are as follows:

(1) The carrier shall submit to the FBI estimated and/or incurred costs by line item with supporting information, adequately cross-referenced, suitable for detailed analysis.

(2) A cost element breakdown as described in § 100.16(h) shall be attached for each proposed line item and must reflect any specific requirements established by the FBI.

(3) Supporting breakdowns shall be furnished for each cost element, consistent with the carrier's cost accounting system.

(4) When more than one line item is proposed, summary total amounts covering all line items shall be furnished for each cost element.

(5) Depending on the carrier's accounting system, the carrier shall provide breakdownS for the following categories of cost elements, as applicable:

(i) *Materials.* Provide a consolidated cost summary of individual material quantities included in the various tasks, orders, or agreement line items being proposed and the basis upon which they were developed (vendor quotes, invoice prices, etc.). Include raw materials, parts, software, components, and assemblies. For all items proposed, identify the item, source, quantity, and cost.

(ii) *Direct labor.* Provide a time-phased (e.g., monthly, quarterly) breakdown of labor hours, rates, and costs by appropriate category, and furnish the methodologies used in developing estimates.

(iii) *Allocable direct costs.* Indicate how allocable costs are computed and applied, including cost breakdowns, and showing trends and budgetary data, to provide a basis for evaluating the reasonableness of proposed rates. Indicate the rates used and provide an appropriate explanation.

(iv) *Subcontracting costs.* For any subcontractor costs submitted for reimbursement, the carrier is responsible for ensuring that documentation requirements set forth herein are passed on to any and all subcontractors utilized in the carrier's efforts to meet CALEA requirements.

(v) *Other costs.* List all other costs not otherwise included in the categories described above (e.g., special tooling, travel, computer and consultant services) and provide bases for costs.

(e) As part of the specific information required, the carrier shall submit with its cost estimate and clearly identify as such, costs that are verifiable and factual. In addition, the carrier shall submit information reasonably required to explain its estimating process, including:

(1) The judgmental factors applied and the mathematical or other methods used in the estimate, including those used in projecting from known data; and

(2) The nature and amount of any contingencies included in the proposed estimate.

(f) There is a clear distinction between submitting cost data and merely making available books, records, and other documents without identification. The requirement for submission of cost data is met when all accurate cost data reasonably available to the carrier have been submitted, either actually or by specific identification, to the FBI. As later information comes into the carrier's possession, it must be promptly submitted to the FBI. The requirement for submission of cost data continues up to the time of final reimbursement.

(g) In submitting its estimate, the carrier must include an index, appropriately referenced, of all the cost data and information accompanying or identified in the estimated. In addition, any future additions and/or revisions, up to the date of agreement on the costs, must be annotated in a supplemental index.

(h) Headings for submission are as follows:

(1) Total Project Cost: Summary.

(i) Cost Elements (Enter appropriate cost elements.).

(ii) Proposed Cost Estimate—Total Cost (enter those necessary and reasonable costs that in the carrier's judgment will properly be incurred in efficient completion of CALEA requirements. When any of the costs in this have already been incurred (e.g., under a letter contract), describe them on an attached support schedule.).

(iii) Proposed Cost Estimate—Unit Cost (Enter the unit costs for each cost element.).

(iv) Supporting Material (Identify the attachment in which the information supporting the specific cost element may be found. Attach separate pages as necessary.).

(2) Total Project Costs: Detail (at Switch Level, Research & Development, or Project level, as appropriate).

(i) Cost Elements (Enter appropriate cost elements.).

(ii) Proposed Cost Estimate—Total Cost (enter those necessary and reasonable costs that in the carrier's judgment will properly be incurred in efficient completion of CALEA requirements. When any of the costs in this have already been incurred (e.g., under a letter contract), describe them on an attached supporting schedule.).

(iii) Proposed Cost Estimate—Unit Cost (Enter the unit costs for each element.).

(iv) Supporting Material (Identify the attachment in which the information supporting the specific cost element may be found. Attach separate pages as necessary.).

§ 100.17 Request for payment.

(a) The carrier shall provide sufficient supporting documentation at the time of submission of request for payment to allow adequate analysis and evaluation of the incurred costs. The FBI reserves the right to request additional cost data from carriers in order to ensure compliance with this part.

(b) Instructions for submission of the supporting documentation for the request for payment are as follows:

(1) The carrier shall submit to the FBI incurred costs by line item with supporting information, adequately cross-referenced, suitable for detailed analysis.

(2) A cost element breakdown § 100.17(f) shall be attached for each agreed upon line item and must reflect any specific requirements established by the FBI.

(3) Supporting breakdowns shall be furnished for each cost element, consistent with the carrier's cost accounting system.

(c) When more than one line item has been agreed upon, summary total amounts covering all line items shall be furnished for each cost element. If agreement has been reached with FBI representatives on use of forward costing rates/factors, identify the agreement, include a copy, and describe its nature. Depending on the carrier's accounting system, breakdowns shall be provided to the FBI for the following categories of cost elements, as applicable:

(1) *Materials.* Provide a consolidated cost summary of individual material quantities included in the various tasks, orders, or agreement line items and the basis upon which they were determined (vendor invoices, time sheets, payroll records, etc.). Include raw materials, parts, software, components, and assemblies. For all reimbursable items, identify the item, source, quantity, and cost.

(2) *Direct labor.* Provide time sheets and labor rate justification for all direct labor charged to this agreement. Include a breakdown of labor hours, rates, and cost by appropriate category, and furnish the methodologies used in identifying these costs.

(3) *Allocable direct costs.* Indicate how allocable costs are computed and applied, including cost breakdowns, comparing estimates to actual data as a basis for evaluating the reasonableness of actual costs.

(4) *Subcontracting costs.* For any subcontractor costs submitted for reimbursement, along with a copy of the invoice, the carrier must provide documentation that costs incurred are just and reasonable.

(5) *Other costs.* List all other costs not otherwise included in the categories described above (e.g., special tooling, travel, computer and consultant services) and provide documentation of these costs.

(d) There is a clear distinction between submitting cost data and merely making available books, records, and other documents without identification.

(1) The requirement for submission of cost data is met when all accurate cost data reasonably available to the carrier have been submitted, either actually or by specific identification, to the FBI.

(2) As later information comes into the carrier's possession, it must be promptly submitted to the FBI.

(3) The requirement for submission of cost data continues up to the time of final reimbursement.

(e) In submitting its invoice, the carrier must include an index, appropriately referenced, of all the cost data and information accompanying or identified in the estimate. With any future additions and/or revisions to an estimate, the carrier must provide a supplemental index, up to the date of the agreement on the costs.

(f) Headings for submission are as follows:

(1) Total Project Cost: Summary.

(i) Cost Elements (Enter appropriate cost elements.).

(ii) Actual Costs Incurred—Total Cost (Enter those necessary and reasonable costs that were incurred in the efficient completion of CALEA requirements.).

(iii) Actual Costs Incurred—Unit Cost (Enter the unit costs for each cost element.).

(iv) Supporting Material (Identify the attachment in which the information supporting the specific cost element may be found. Attach separate pages as necessary.).

(2) Total Project Costs: Detail (at Switch Level, Research & Development, or Project level, as appropriate).

(i) Cost Elements (Enter appropriate cost elements.).

(ii) Actual Costs Incurred—Total Cost (Enter those necessary and reasonable costs that were incurred in the efficient completion of CALEA requirements.).

(iii) Actual Costs Incurred—Unit Cost (Enter the unit costs for each cost element.).

(iv) Supporting Material (Identify the attachment in which the information supporting the specific cost element may be found. Attach separate pages as necessary.).

§ 100.18 Audit.

(a) *General.* In order to evaluate the accuracy, completeness, and currency of the cost data, the FBI or other representatives of the Government shall have the right to examine and audit all of the carrier's supporting materials.

(1) These materials include, but are not limited to books, records, documents, and other data, regardless of form (e.g., machine readable media such as disk, tape) or type (e.g., data bases, applications software, data base management software, utilities), including computations and projections related to proposing, negotiating, costing, or performing CALEA compliance efforts or modifications.

(2) The right of examination shall extend to all documents necessary to permit adequate evaluation of the cost data submitted, along with the computations and projections used.

(b) *Audits of request for payment.* The carrier shall maintain and the FBI or representatives of the Government shall have the right to examine and audit supporting materials.

(1) These materials include, but are not limited to, books, records, documents, and other evidence and accounting procedures and practices, regardless of form (e.g., machine readable media such as disk, tape) or type (e.g., data bases, applications software, data based management software, utilities), sufficient to reflect properly all costs claimed to have been incurred, or anticipated to be incurred, in performing the CALEA compliance effort.

(2) This right of examination shall include inspection at all reasonable times of the carrier's plants, or parts of them, engaged in performing the effort.

(c) *Reports.* If the carrier is required to furnish cost, funding, or performance reports, the FBI or representatives of the Government shall have the right to examine and audit books, records, other documents, and supporting materials, for the purpose of evaluating the effectiveness of the carrier's policies and procedures to produce data compatible with the objectives of these reports and the data reported.

(d) *Availability.* The carrier shall make available at its office at all reasonable times the costs and support material described herein, for examination, audit, or reproduction, until five (5) years after final reimbursement payment. In addition,

(1) If the CALEA compliance effort is completely or partially terminated, the records relating to the work terminated shall be made available for five (5) years after any resulting final termination settlement; and

(2) Records relating to appeals, litigation or the settlement of claims arising under or relating to the CALEA compliance effort shall be made available until such appeals, litigation, or claims are disposed of.

(e) *Subcontractors.* The carrier shall ensure that all terms and conditions herein are incorporated in any agreement with a subcontractor that may be utilized by the carrier to perform any or all portions of this agreement.

§ 100.19 Reduction for defective cost data.

(a) The cost shall be reduced accordingly and the agreement shall be modified to reflect the reduction if any cost estimate negotiated in connection with the CALEA compliance effort, or any cost reimbursable under the effort, or any data modification is increased by any significant amount because:

(1) The carrier or a subcontractor furnished cost data that were not complete, accurate, and current;

(2) A subcontractor or prospective subcontractor furnished the carrier cost data that were not complete, accurate, and current; or

(3) Any of these parties furnished data of any description that were not accurate.

(b) Any reduction in the negotiated cost under § 100.19(a) due to defective data from a prospective subcontractor that was not subsequently awarded the subcontract shall be limited to the amount by which either the actual subcontract or the actual cost to the carrier, if there was no subcontract, was less than the prospective subcontract cost estimate submitted by the carrier, provided that the actual subcontract cost was not itself affected by defective cost data.

(c) If the FBI determines under § 100.19(a) that a cost reduction should be made, the carrier shall not raise the following matters as a defense:

(1) The carrier or subcontractor was a sole source supplier or otherwise was in a superior bargaining position and thus the costs of the agreement would not have been modified even if accurate, complete, and current cost data had been submitted;

(2) The FBI should have known that the cost data at issue were defective even though the carrier or subcontractor took no affirmative action to bring the character of the data to the attention of the FBI;

(3) The carrier or subcontractor did not submit accurate cost data. Except as prohibited, an offset in an amount determined appropriate by the FBI based upon the facts shall be allowed against the cost reimbursement of an agreement amount reduction if the carrier certifies to the FBI that, to the best of the carrier's knowledge and belief, the carrier is entitled to the offset in the amount requested and the carrier proves that the cost data were available before the date of agreement on the cost of the agreement (or cost of the modification) and that the data were not submitted before such date. An offset shall not be allowed if the understated data were known by the carrier to be understated when the agreement was signed; or the Government proves that

the facts demonstrate that the agreement amount would not have increased even if the available data had been submitted before the date of agreement on cost; or

(4) In the event of an overpayment, the carrier shall be liable to and shall pay the United States at that time such overpayment as was made, with simple interest on the amount of such overpayment to be computed from the date(s) of overpayment to the carrier to the date the Government is repaid by the carrier at the applicable underpayment rate effective for each quarter prescribed by the Secretary of the Treasury under 26 U.S.C. 6621(a)(2).

§ 100.20 Accounting for unallowable costs.

To ensure that the Government does not reimburse carriers for unallowable costs, the following provisions are included:

(a) Costs that are expressly unallowable or mutually agreed to be unallowable, including mutually agreed to be unallowable directly associated costs, shall be identified and excluded from any billing, claim, or proposal applicable to reimbursement under CALEA. When an unallowable cost is incurred, its directly associated costs are also unallowable.

(b) The detail and depth of records required as backup support for cost estimates, billings, or claims shall be those which are adequate to establish and maintain visibility of identified unallowable costs, including their directly associated costs. Unallowable costs involved in determining rates used for standard costs, or for allocable cost proposals or billing, need be identified only at the time rates are proposed, established, revised, or adjusted. These requirements may be satisfied by any form of cost identification which is adequate for purposes of cost determination and verification.

§ 100.21 Confidentiality of trade secrets/proprietary information.

With respect to any information provided to the FBI under this part that is identified as company proprietary information, it shall be treated as privileged and confidential. It shall not be disclosed outside the government for any reason inclusive of Freedom of Information requests, without the prior written approval of the company. Information provided will be used exclusively for the implementation of CALEA. This restriction does not limit the government's right to use the information provided if obtained from any other source without limitation.

[FR Doc. 96–11724 Filed 5–9–96; 8:45 am]

BILLING CODE 4410–02–M

POSTAL SERVICE

39 CFR Part 233

Addition of Commercial Espionage to Mail Cover Regulations

AGENCY: Postal Service.

ACTION: Proposed rule.

SUMMARY: This proposed rule will amend the United States Postal Service's mail cover regulations to add commercial espionage by foreign sources as a criminal activity for which national security mail covers may be authorized. This change is effected by expanding the definition of ''protection of the national security'' found at 39 CFR 233.3(c)(9) to include commercial espionage.

DATES: Comments must be received on or before June 10, 1996.

ADDRESSES: Written comments should be mailed or delivered to Counsel, Postal Inspection Service, 475 L'Enfant Plaza SW, Room 3411, Washington, DC 20260–2181.

FOR FURTHER INFORMATION CONTACT: Henry J. Bauman, Counsel, Postal Inspection Service, (202) 268–4415.

SUPPLEMENTARY INFORMATION: Postal Service regulations on mail covers are published in Title 39 of the Code of Federal Regulations (CFR) at § 233. Paragraph (c)(9) of § 233.3 currently defines ''protection of the national security'' as ''actual or potential threats to the security of the United States of America by a foreign power or its agents.'' This definition will be expanded to include commercial espionage.

Commercial espionage by foreign sources has become an increasing threat to the economic well-being and ability of the United States to compete in the international market. For the purposes of this proposed revision, ''commercial espionage'' is defined as either ''economic espionage'' or ''industrial espionage.'' According to the Federal Bureau of Investigation (FBI) white paper, FBI Strategy to Address the Problem of Economic Espionage and Industrial Espionage (Washington, DC: FBI Headquarters, undated), ''economic espionage'' is ''government-directed, sponsored, or coordinated intelligence activity, which may or may not constitute violation of the law, conducted for the purpose of enhancing that country's or another country's economic competitiveness by the use of the information by the foreign government or by providing it to a foreign business entity thereby giving that entity a competitive advantage in the marketplace.'' ''Industrial espionage'' is defined by the FBI as ''individual or private business entity sponsorship or coordination of intelligence activity conducted for the purpose of enhancing a private business and its competitive advantage in the marketplace, which is a violation of law.''

Revising the Postal Service's national security mail cover regulations to include commercial espionage will enhance the ability of law enforcement to protect national security.

List of Subjects in 39 CFR Part 233

Administrative practice and procedures, Banks and banking, Credit, Crime, Law Enforcement, Postal Service, Privacy, Seizure and forfeiture.

Accordingly, 39 CFR 233 is proposed to be amended as set forth below.

PART 233—INSPECTION SERVICE/INSPECTOR GENERAL AUTHORITY

1. The authority citation for part 233 continues to read as follows:

Authority: 39 U.S.C. 101, 401, 402, 403, 404, 406, 410, 411, 3005(e)(1); 12 U.S.C. 3401–3422; 18 U.S.C. 981, 1956, 1957, 2254, 3061; 21 U.S.C. 881; Inspector General Act of 1978, as amended (Pub. L. No. 95–452, as amended), 5 U.S.C. App.3.

2. Paragraph (c)(9) of § 233.3 is revised to read as follows:

§ 233.3 Mail covers.

* * * * *

(c) * * *

(9) *Protection of the national security* means to protect the United States from any of the following actual or potential threats to its security by a foreign power or its agents:

(i) An attack or other grave, hostile act;

(ii) Sabotage, or international terrorism; or

(iii) Clandestine intelligence activities, including commercial espionage.

* * * * *

Stanley F. Mires,

Chief Counsel, Legislative.

[FR Doc. 96–11768 Filed 5–9–96; 8:45 am]

BILLING CODE 7710–12–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[IL102–1–6693; FRL–5503–9]

Approval and Promulgation of Air Quality Implementation Plans; Illinois: Motor Vehicle Inspection and Maintenance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve portions and to conditionally approve other portions of a vehicle inspection and maintenance (I/M) State Implementation Plan (SIP) revision submitted by the State of Illinois on June 29, 1995, based on the State's April 22, 1996, letter of commitment to submit certain items within one year of the final conditional approval. This revision provides for the adoption and implementation of an enhanced I/M program in both the Chicago severe ozone nonattainment area and the East St. Louis moderate ozone nonattainment area. Both areas are required to attain the National Ambient Air Quality Standards (NAAQS) as specified under the Clean Air Act (Act) by 2007 and 1996 respectively. Illinois indicates that the implementation of this important program in the two areas stated above, will reduce vehicle emissions which contribute to the formation of urban smog in Illinois by more than 38 tons per day. In support of the proposed conditional approval of the SIP revision, the State has submitted the State's Request-For-Proposals as supplemental information to the SIP. In addition, the State has committed in an April 22, 1996, letter to submit to EPA as supplemental information in support of the SIP, the State's final I/M contract and any rules necessary to address the requirements identified in the analysis section of this document.

DATES: Comments must be received on or before June 10, 1996.

ADDRESSES: Copies of Illinois' I/M SIP submittal, EPA's proposals and rulemakings, and other documents pertinent to this proposed notice are available at the following address: U.S. Environmental Protection Agency, Region 5, Air and Radiation Division, Air Programs Branch, 77 West Jackson Boulevard, Chicago, Illinois 60604.

Comments on this proposed rule should be addressed to: J. Elmer Bortzer, Chief, Regulation Development Section, Air Programs Branch (AR–18J), United States Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604.

FOR FURTHER INFORMATION CONTACT: Francisco J. Acevedo, Environmental Engineer, Regulation Development Section, Air Programs Branch (AR–18J), United States Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886–6061.

Anyone wishing to come to Region 5 offices should first contact Francisco J. Acevedo.

SUPPLEMENTARY INFORMATION:

I. Introduction

Motor vehicles are significant contributors of volatile organic compounds (VOC), carbon monoxide (CO), and nitrogen oxide (NO_X) emissions. The motor vehicle inspection and maintenance program is an effective means of reducing these emissions. Despite improvements in emission control technology in past years, mobile sources in urban areas continue to remain responsible for roughly half of the emissions of VOC causing ozone, and most of the emissions of CO. They also emit substantial amounts of nitrogen oxides and air toxics. This is because the number of vehicle miles traveled has doubled in the last 20 years to 2 trillion miles per year, offsetting much of the technological progress in vehicle emission control over the same period. Projections indicate that the steady growth in vehicle miles will continue.

Under the Act, the EPA is pursuing a three-point strategy to achieve emission reductions from motor vehicles. The development and commercialization of cleaner vehicles and cleaner fuels represent the first two elements of the strategy. These developments will take many years before cleaner vehicles and fuels dominate the fleet and favorably impact the environment. This document deals with the third element of the strategy, inspection and maintenance, which is aimed at the reduction of emissions from the existing fleet by ensuring that vehicles are maintained to meet the emission standards established by EPA. Properly functioning emission controls are necessary to keep pollution levels low. The driving public is often unable to detect a malfunction of the emission control system. While some minor malfunctions can increase emissions significantly, they do not affect drivability and may go unnoticed for a long period of time. Effective I/M programs can identify excessive emissions and assure repairs. The EPA projects that sophisticated I/M programs such as the one being proposed in this rulemaking in Illinois will identify emission related problems and prompt the vehicle owner to obtain timely repairs thus reducing emissions.

The Act requires that polluted cities adopt either a ''basic'' or ''enhanced'' I/M program, depending on the severity of the pollution and the population of the area. Moderate ozone nonattainment areas, plus marginal ozone areas with existing or previously required I/M programs in Census-defined urbanized areas, fall under the ''basic'' I/M requirements. Basic and enhanced I/M programs both achieve their objective by identifying vehicles that have high emissions as a result of one or more malfunctions, and requiring them to be repaired. An ''enhanced'' I/M program covers more vehicles in operation in the fleet, employs inspection methods which are better at finding high emitting vehicles, and has additional features to better assure that all vehicles are tested properly and effectively repaired. The Act directed EPA to establish a minimum performance standard for enhanced I/M programs. The standard is based on the performance achievable by annual inspections in a centralized test program. States have flexibility to design their own programs if they can show that their program is as effective as the model program used in the performance standard. Naturally, the more effective the program the more credit a State will get towards the emission reduction requirement. An effective program will help to offset emissions associated with growth in vehicle use and allow for industrial and/or commercial growth.

The EPA and the States have learned a great deal about what makes an I/M program effective since the Clean Air Act of 1977 first required I/M programs for polluted areas. There are three major keys to an effective program:

(1) Given the advanced state of current vehicle design and anticipated technology changes, the ability to accurately fail problem vehicles and pass clean ones requires improved test equipment and test procedures;

(2) Comprehensive quality control and aggressive enforcement are essential to assuring the testing is done properly;

(3) Skillful diagnostics and capable mechanics are important to assure that failed cars are fixed properly.

These three factors are missing in most older I/M programs. Specifically, the idle and 2500 RPM/idle short tests and anti-tamper inspections used in current I/M programs are not as effective in identifying and reducing in-use emissions from the types of vehicles in the current and future fleet. Also, covert audits by EPA and State agencies

typically discover improper inspection and testing 50 percent of the time in test-and-repair stations indicating poor quality control. Experience has shown that quality control at high-volume test only stations is usually much better. And, finally, diagnostics and mechanics training are often poor or nonexistent.

On November 5, 1992 (57 FR 52950), EPA established a high-tech emission test for high-tech cars. This I/M test, known as the IM240 test, is so effective that biennial test programs yield almost the same emission reduction benefits as annual programs. The test can also accurately measure NO_X emissions where NO_X is important to address an ozone problem. The addition of the pressure and purge test increases the benefit even more and results in lower testing costs and consumer time demands. The pressure test is designed to find leaks in the fuel system, and the purge test evaluates the functionality of the vapor control system. In addition, EPA published changes to the I/M rule in the Federal Register on October 18, 1995, (60 FR 48029) in order to provide greater flexibility to States required to implement I/M programs.

II. Background

The State of Illinois currently contains two ozone nonattainment areas which are required to implement I/M programs in accordance with the Act. The Chicago severe-17 ozone nonattainment area contains the Chicago, Aurora, Crystal Lake, Elgin, Joliet, and Round Lake Beach-McHenry urbanized areas. The Federal I/M rule requires the Chicago urbanized area to implement an enhanced I/M program. Since the I/M rule does not require enhanced I/M programs in severe urbanized areas with a Census population of less than 200,000, the remaining five cities in the Chicago nonattainment area will be required to implement only a basic I/M program based on their 1990 Census-defined urbanized area populations. The East St. Louis moderate ozone nonattainment area contains the Illinois portion of the St. Louis and Alton urbanized areas. Both areas are required to implement a Basic I/M program in the nonattainment area. On June 29, 1995, IEPA submitted to EPA a SIP revision for the implementation of an enhanced I/M program to cover both the Chicago and the East St. Louis nonattainment areas. This submittal includes the Vehicle Emissions Inspection Law of 1995 (625 ILCS 5/13B), P.A. 88–533, which became effective January 18, 1994. That statute provides authority for IEPA to implement an enhanced I/M program and meet EPA's requirements for such a program. P.A. 88–533 mandates enhanced I/M testing for the Metro-East area and certain portions of the Chicago nonattainment area. In addition, the Illinois submittal includes I/M regulations (R94–19 and R94–20) adopted on December 1, 1994, by the Illinois Pollution Control Board (Board), which include emissions standards based upon EPA's preferred IM240 loaded mode exhaust emissions standard. On December 23, 1994, the amended rule for R94–20 was published in the Illinois State Register and its effective date was December 12, 1994. On December 30, 1994, the amended rule R94–19 was published in the Illinois Register and had an effective date of December 14, 1994. On April 22, 1996, IEPA submitted the State's I/M Request-For-Proposal as part of the Illinois SIP submittal.

Under the Environmental Protection Act [415 ILCS 5 (1992)], the Board has the authority to adopt air pollution regulations for the State of Illinois. The adopted regulations and the legislation submitted by Illinois changes the existing program from a basic I/M program to a fully enhanced I/M program in both of Illinois' ozone nonattainment areas. EPA summarizes the requirements of the Federal I/M regulations, as found in 40 CFR 51.350–51.373, and its analysis of the state submittal below. Parties desiring additional details on the Federal I/M regulation are referred to the November 5, 1992, Federal Register notice (57 FR 52950), or 40 CFR 51.350–51.373.

III. EPA's Analysis of the Illinois, Enhanced I/M Program

As discussed above, section 182 of the Act requires that States adopt and implement updated regulations for I/M programs in moderate and above ozone nonattainment areas. The following sections of this notice summarize the requirements of the Federal I/M regulations and address whether the elements of the State's submittal comply with the Federal rule.

Applicability 40 CFR 51.350

Section 182(c)(3) of the Act and 40 CFR 51.350(a) require States which contain areas classified as serious or worse ozone nonattainment and containing metropolitan statistical areas (MSAs) with a population of 200,000 or more to implement an enhanced I/M program. As noted above, the State of Illinois contains the Aurora, Chicago, Crystal Lake, Elgin, Joliet, and Round Lake beach-McHenry urbanized areas in its Chicago Severe-17 ozone nonattainment area, but the Chicago urbanized area is the only area which contains a population of more than 200,000, based on 1990 Census data. The remaining urbanized areas in the Chicago nonattainment area with populations less than 200,000 are required to implement a basic I/M program. In addition, section 182(b)(4) of the Act and 40 CFR part 51.530(a) require States with moderate ozone nonattainment areas containing 1990 census-defined urbanized areas to implement a basic I/M program. The State of Illinois contains the East St. Louis moderate nonattainment area where this requirement applies.

The Illinois submittal contains the legal authority and regulations necessary for IEPA to establish the program boundaries and operate an enhanced I/M program in ozone nonattainment areas stated above. P.A. 88–533 specifies the geographic boundaries of the program in both ozone nonattainment areas. The program boundaries described in the Illinois submittal meet the Federal I/M requirements under Sec. 51.350 and are approvable. The Federal I/M regulation requires that the State I/M program must operate until it is no longer necessary. EPA has determined that a SIP which does not terminate prior to the attainment deadline for each applicable area (i.e. 2007 for the Chicago severe-17 ozone nonattainment area, and 1996 for the Metro-East moderate ozone nonattainment area) satisfies this requirement. The State I/M submittal does not contain a termination provision and is therefore approvable. EPA proposes to approve this section of the Illinois submittal.

Enhanced I/M Performance Standard 40 CFR 51.351

The enhanced I/M program must be designed and implemented to meet or exceed a minimum performance standard, expressed in area-wide average grams per mile (gpm), for emission levels of certain pollutants. The performance standard shall be established using local characteristics, such as vehicle mix and local fuel controls, and the following model I/M program parameters: network type, start date, test frequency, model year coverage, vehicle type coverage, exhaust emission test type, emission standards, emission control device, evaporative system function checks, stringency, waiver rate, compliance rate and evaluation date. The emission levels achieved by the State's program design shall be calculated using the most current version, at the time of submittal, of the EPA mobile source emission factor model. At the time of the Illinois submittal, the most current version was

MOBILE5a. Areas shall meet or exceed the performance standard for the pollutants which cause them to be subject to I/M requirements. In the case of ozone nonattainment areas, the performance standard must be met for both nitrogen oxides (NO_X) and volatile organic compounds (VOCs). Urban Airshed Modeling (UAM) has been conducted in both the Chicago and St. Louis regions. In the Chicago area, the UAM has demonstrated that control of NO_X within the nonattainment area is counterproductive in controlling ambient ozone. IEPA has petitioned for, and has received from EPA, a waiver from Clean Air Act NO_X control requirements, including the requirement to meet the NO_X enhanced I/M performance standard. EPA is currently in the process of evaluating the UAM data and an IEPA NO_X waiver request for the St. Louis region. NO_X testing will be restricted to tests conducted for program evaluation purposes in accordance with 40 CFR Part 51.353(c).

The June 30, 1995, Illinois submittal includes three alternative enhanced program options based on the use of either ASM5015, ASM2, or IM240 networks. All three options use the following program design parameters: Centralized test only network; 1986 start date; biennial frequency; 1968 and newer model year coverage; Vehicle type include LDGV, LDGT1, LDGT2 and HDGV; IM240 for 1981 and newer vehicles, and idle for 1968–1980 LDGV's and LDGT's and 1968 and later HDGV's; purge test on 1981 and newer LDGV's and LDGT's undergoing either ASM or IM240; pressure test of gas cap; stringency rate of 20 percent for 1980 and older vehicles; waiver rate of 3 percent and a 96 percent compliance rate.

The Illinois program design parameters meet the Federal I/M regulations and are approvable. The emission levels achieved by the State, for each area, were modeled using MOBILE5a. The modeling demonstration was performed correctly, using local characteristics where available, and it demonstrated that the program design will meet the enhanced I/M performance standard, expressed in grams per mile, for VOCs and NO_X for each milestone and for the attainment deadline. The modeling demonstration submitted by the State is approvable. EPA proposes to approve this section of the submittal.

Network Type and Program Evaluation 40 CFR 51.353

Enhanced I/M programs shall be operated in a centralized test only format, unless the State can demonstrate that a decentralized program is equally effective in achieving the enhanced I/M performance standard. The enhanced program shall include an ongoing evaluation to quantify the emission reduction benefits of the program and to determine if the program is meeting the requirements of the Act and the Federal I/M regulations. The SIP shall include details on the program evaluation and a schedule for submittal of biennial evaluation reports, data from a State monitored or administered mass emission test of at least 0.1 percent of the vehicles subject to inspection each year, description of the sampling methodology, the data collection and analysis system and the legal authority enabling the evaluation program.

The State legislative authority and the State I/M regulations provide for a centralized, test-only network. Illinois' centralized, test only network type is approvable. The submittal does not, however, include provisions for on-going program evaluation to satisfy all of the requirements of 40 CFR part 51.353. Specifically, the State must submit schedules for program evaluations and methodologies by which this biennial program evaluation will be carried out, as required by 40 CFR part 51.353. EPA proposes to conditionally approve this section of the Illinois enhanced I/M SIP based on the April 22, 1996, letter and phone conversation record committing to submit to EPA as supplemental information in support of the SIP the necessary documentation within one year of the final conditional approval. In addition, the State has committed to submit to EPA biennial program evaluation reports meeting the requirements of 40 CFR part 51.353 starting at the end of the program's first biennial cycle.

Adequate Tools and Resources 40 CFR 51.354

The Federal I/M regulation requires States to demonstrate that adequate funding of the program is available. A portion of the test fee or a separately assessed per year vehicle fee shall be collected, placed in a dedicated fund and used to finance the program. Alternative funding approaches are acceptable if it is demonstrated that the funding can be maintained. Reliance on funding from a State or local General Fund is not acceptable unless doing otherwise would be a violation of the State's constitution. The SIP shall include a detailed budget plan which describes the source of funds for personnel, program administration, program enforcement and purchase of equipment. The SIP shall also detail the number of personnel dedicated to the quality assurance program, data analysis, program administration, enforcement, public education and assistance and other necessary functions. A.P. 88–533 prevents the IEPA from charging motor vehicle owners for inspections required under this law. Instead, A.P. 88–533 states that the Vehicle Inspection Fund, which was a fund created in the State treasury for the purpose of receiving money from the Motor Fuel Tax and other sources, shall be used for the payment of the cost of the program, including reimbursement of those agencies of the State that incur expenses in the administration and enforcement of the program. EPA proposes to approve this section of the Illinois submittal.

Test Frequency and Convenience 40 CFR 51.355

The enhanced I/M performance standard assumes an annual test frequency; however, other schedules may be approved if the performance standard is achieved. The SIP shall describe the test year selection scheme and shall include the legal authority, regulations or contract provisions necessary to implement and enforce the test frequency requirement. The program shall be designed to provide convenient service to motorists by ensuring short waiting times, short driving distances and regular testing hours. The Illinois enhanced I/M law of 1995 provides the legal authority to implement and enforce biennial test frequency for all subject vehicles. New vehicles are exempt from testing for two years, requiring the vehicle to be initially tested in the second calendar year after the vehicle model year. Based on the performance standard modeling provided by the State, the enhanced I/M program meets the performance standard accounting for biennial test frequency. P.A. 88–533 also requires that the program be designed so that covered vehicle owners reside within 12 miles of an official inspection station. In addition, the law requires the program to be designed in such a way that sufficient inspection capacity at the station is so that the usual wait before the start of an inspection does not exceed twenty minutes. The test frequency and convenience section is approvable and EPA is proposing to approve.

Vehicle Coverage 40 CFR 51.356

The performance standard for enhanced I/M programs assumes coverage of all 1968 and newer model year light duty vehicles and light duty trucks up to 8,500 pounds gross vehicle

weight rating (GVWR), and includes vehicles operating on all fuel types. Other levels of coverage may be approved if the necessary emission reductions are achieved. Vehicles registered or required to be registered within the I/M program area boundaries, and fleets primarily operated within the I/M program area boundaries belonging to the covered model years and vehicle classes comprise the subject vehicles. Fleets may be officially inspected outside the normal I/M program test facilities, if such alternatives are approved by the program administration, but shall be subject to the same test requirements using the same quality control standards as non-fleet vehicles and shall be inspected in independent, test-only facilities, according to the requirements of 40 CFR part 51.353(a).

The Federal I/M regulation requires that the SIP shall include the legal authority or rule necessary to implement and enforce the vehicle coverage requirement, a detailed description of the number and types of vehicles to be covered by the program and a plan for how those vehicles are to be identified, including vehicles that are routinely operated in the area but may not be registered in the area, and a description of any special exemptions, including the percentage and number of vehicles to be impacted by the exemption.

The Illinois Vehicle Inspection Law of 1995 requires coverage of all 1968 and newer vehicles registered or required to be registered in the I/M program area, except those vehicles which run on diesel or exclusively by electricity. The modeling demonstration submitted with the SIP narrows the vehicle coverage to LDGV, LDGT1, and LDGT2. The Illinois legislation provides the legal authority to implement and enforce the vehicle coverage. This level of coverage is approvable because it provides the necessary emission reductions. The modeling demonstration does contain estimates of the number of registered vehicles in the area. However, the State's June 29, 1995, SIP submittal does not adequately address fleet testing requirements. Existing legislation allows for the self testing of fleets, but the submittal fails to address the specific requirements involved in fleet testing. The State also did not provide a description of the impact vehicle exemptions will have on the subject fleet. The modeling demonstration submitted by the State does not account for these exemptions in the emission reduction analysis. The State must describe the extent of the exemption's impact, in accordance with 40 CFR part 51.356, in order for EPA to fully approve this section of the State submittal. EPA proposes to conditionally approve this section based on the April 22, 1996, letter to EPA committing to address the requirements of 40 CFR 51.356 with regard to fleets, within one year of the final conditional approval.

Test Procedures and Standards 40 CFR 51.357

Written test procedures and pass/fail standards are required to be established and followed for each model year and vehicle type included in the program. Federal test procedures and standards are found in 40 CFR 51.357 and in the EPA document entitled ''High-Tech I/M Test Procedures, Equipment Standards, Quality Control Requirements, and Equipment Specifications'', EPA–AA–EPSD–IM–93–1, finalized in April, 1994. A.P. 88–533 provides the State the authority to establish test procedures according to the needs of the program. The Illinois submittal also includes I/M regulations (R94–19 and R94–20) adopted on December 1, 1994, by the Illinois Pollution Control Board (Board) which include emissions standards based upon EPA's preferred IM240 loaded mode exhaust emissions standard. IEPA has asked I/M contract bidders to address in detail the requirements of this section in its Request-For-Proposal (RFP). EPA proposes to conditionally approve this section of the SIP based on the State's commitment to submit to EPA as supplemental information in support of the SIP its final signed I/M contract addressing the requirements of 40 CFR part 51.357 within one year of EPA's final conditional approval.

Test Equipment 40 CFR 51.358

The Federal regulation requires computerized test systems for performing any measurement on subject vehicles. The Federal I/M regulations requires that the State SIP submittal include written technical specifications for all test equipment used in the program. The specifications shall describe the emission analysis process, the necessary test equipment, the required features and written acceptance testing criteria and procedures.

A.P. 88–533 provides the general authority for the State to establish the designation of official test equipment and testing procedures. The Illinois submittal also includes I/M regulations (R94–19 and R94–20) which include emissions standards based upon EPA's preferred IM240 loaded mode exhaust emissions standard. IEPA has addressed the requirements of this section in its RFP released February 29, 1996. EPA proposes to conditionally approve this section of the SIP based on the State's April 22, 1996, commitment to submit to EPA as supplemental information in support of the SIP its final signed contract addressing the requirements of 40 CFR part 51.358 within one year of EPA's final conditional approval.

Quality Control 40 CFR 51.359

Quality control measures shall ensure that emission measurement equipment are calibrated and maintained properly, and that inspection, calibration records and control charts are accurately created, recorded and maintained. The Illinois submittal contains general legal authority in A.P. 88–533 which requires IEPA to establish an enhanced program containing procedures to assure the correct operation, maintenance and calibration of test equipment, and also procedures for certifying test results and for reporting and maintaining relevant data and records. Illinois' RFP requires bidders as part of their Technical proposal to submit a Quality Assurance Plan which addresses the requirements of this section. EPA proposes to conditionally approve this section of the SIP based on the State's April 22, 1996 commitment to submit to EPA as supplemental information in support of the SIP its final signed contract and the contractor's Quality Assurance Plan addressing the quality control requirements of 40 CFR part 51.359 within one year of EPA's final conditional approval.

Waivers and Compliance Via Diagnostic Inspection 40 CFR 51.360

The Federal I/M regulation allows for the issuance of a waiver, which is a form of compliance with the program requirements that allows a motorist to comply without meeting the applicable test standards, as long as prescribed criteria are met. For enhanced I/M programs, an expenditure of at least $450 in repairs, adjusted annually to reflect the change in the Consumer Price Index (CPI) as of 1989, is required in order to qualify for a waiver. Waivers can only be issued after a vehicle has failed a retest performed after all qualifying repairs have been made. Any available warranty coverage must be used to obtain repairs before expenditures can be counted toward the cost limit. Tampering related repairs shall not be applied toward the cost limit. Repairs must be appropriate to the cause of the failure. Repairs for 1980 and newer model year vehicles must be performed by a recognized repair technician. The Federal regulation

allows for compliance via a diagnostic inspection after failing a retest on emissions and requires quality control of waiver issuance. The SIP must set a maximum waiver rate and must describe corrective action that must be taken if the waiver rate exceeds that committed to in the SIP.

The Illinois SIP submittal contains the necessary authority in A.P. 88–533 to issue waivers, set and adjust cost limits, and administer and enforce the waiver system. The Illinois law requires that IEPA certify whether a vehicle that has failed a vehicle emission retest qualifies for a waiver of the emission inspection standards if the following criteria are met: The vehicle has received all repairs and adjustments for which it is eligible under any emission performance warranty provided under section 207 of the Act; IEPA determines by normal inspection procedures that the vehicle's emission control devices are present and appear to be properly connected and operating; consistent with 40 CFR 51.360 for vehicles required to be tested under the Illinois law, a minimum expenditure of $450 in emission-related repairs exclusive of tampering-related repairs have been made; repairs for vehicles of model year 1981 and later are conducted by a recognized repair technician; evidence of repair is presented consisting of either signed and dated receipts identifying the vehicle and describing the work performed and amount charged for eligible emission-related repairs, or an affidavit executed by the person performing the eligible emission related repairs; and that the repairs have resulted in an improvement in vehicle emissions as determined by comparison of initial and final retest results.

The State of Illinois has chosen not to allow compliance via a complete documented physical and functional diagnosis and inspection which shows that no additional emission-related repairs are needed. The State has set a maximum waiver rate of 3 percent for both pre-1981 and for 1981 and later vehicles. Illinois used MOBILE5a and assumed a maximum waiver rate of 3 percent for 1980 and older model year vehicles and 3 percent for 1981 and newer vehicles. In the event the actual waiver rate exceeds the planned maximum used for estimating the emission reduction benefit, the State will need to remodel to assess the emission reduction benefits based on the actual waiver rate. This section is approvable and EPA is proposing to approve.

Motorist Compliance Enforcement 40 CFR 51.361

The Federal regulations require the use of registration denial to ensure compliance with the requirements of the I/M program unless an exception for use of an alternative is approved. Registration denial enforcement consists of rejecting an application for initial registration or registration for a used vehicle unless the vehicle has complied with the I/M requirements prior to the granting of the application. The SIP shall provide information concerning the enforcement process, legal authority to implement and enforce the program, a commitment to a compliance rate to be used for modeling purposes and to be maintained in practice. The Illinois SIP contains an alternative compliance system to that of registration denial. The Illinois compliance approach uses computer matching of vehicle registration records and inspection records to identify violations. The Illinois Secretary of State (SOS) is required under A.P. 88–533 to suspend either the driving privileges or the vehicle registration, or both, of any vehicle owner who has not complied with the requirements of A.P. 88–533. A suspension under this requirement would not be terminated until proof of compliance has been submitted to the SOS. In the I/M SIP, Illinois commits to the level of motorist enforcement necessary to ensure a compliance rate of no less than 96 percent among subject vehicles in the program area. If it is determined as part of the required program evaluation that the I/M program is not meeting the compliance rate, Illinois will need to investigate the problem and institute changes to improve the compliance rates. EPA proposes to approve this section of the Illinois SIP.

Motorist Compliance Enforcement Program Oversight 40 CFR 51.362

The Federal I/M regulation requires that the enforcement program shall be audited regularly and shall follow effective program management practices, including adjustments to improve operation when necessary. The SIP shall include quality control and quality assurance procedures to be used to insure the effective overall performance of the enforcement system. An information management system shall be established which will characterize, evaluate and enforce the program. The legal authority for the implementation of an I/M program is found in A.P. 88–53. This statute provides the authority necessary to develop and implement the enforcement program oversight element of the I/M program. EPA proposes to conditionally approve this portion of the State's submittal based on the April 22, 1996, letter to EPA committing to addressing the requirements of 40 CFR part 51.362 within one year of the conditional approval.

Quality Assurance 40 CFR 51.363

An ongoing quality assurance program shall be implemented to discover, correct and prevent fraud, waste, and abuse in the program. The program shall include covert and overt performance audits of the inspectors, audits of station and inspector records, equipment audits, and formal training of all state I/M enforcement officials and auditors. A description of the quality assurance program which includes written procedure manuals on the above discussed items must be submitted as part of the SIP. The Illinois submittal contains only a general provision under P.A. 88–533 which requires that the State I/M program provide for procedures to assure the correct operation, maintenance, and calibration of test equipment. Illinois' RFP requires bidders as part of their Technical proposal to submit a Quality Assurance Plan which addresses the requirements of this section. EPA proposes to conditionally approve this section of the SIP based on the State's April 22, 1996 commitment to submit to EPA as supplemental information in support of the SIP its final signed contract and the contractor's Quality Assurance Plan addressing the quality assurance requirements of 40 CFR part 51.363 within one year of EPA's final conditional approval.

Enforcement Against Contractors, Stations and Inspectors 40 CFR 51.364

Enforcement against licensed stations or contractors and inspectors shall include swift, sure, consistent penalties for violation of program requirements. The Federal I/M regulation requires the establishment of minimum penalties for violations of program rules and procedures which can be imposed against stations, contractors and inspectors. The legal authority for establishing and imposing penalties, civil fines, licence suspensions and revocations must be included in the SIP. State quality assurance officials shall have the authority to temporarily suspend station and/or inspector licenses immediately upon finding a violation that directly affects emission reduction benefits. The SIP shall describe the administrative and judicial procedures and responsibilities relevant to the enforcement process. The Illinois

submittal includes the legal authority to establish and impose penalties against station, contractors, and inspectors. In addition, the RFP contains detailed provisions addressing the requirements of this section, including specific monetary penalties established for violation of program rules and procedures. The provisions found in the RFP will be enforceable once a final I/M contract is developed and signed. EPA proposes to conditionally approve this section of the SIP based on the State's April 22, 1996 commitment to submit to EPA as supplemental information in support of the SIP its final signed contract and any necessary administrative rules addressing the requirements of 40 CFR part 51.364 within one year of EPA's final conditional approval.

Data Collection 40 CFR 51.365

In order to manage, evaluate and enforce the program requirements an effective I/M program requires accurate data collection. The Federal I/M regulation requires data to be gathered on each individual test conducted and on the results of the quality control checks of test equipment required under 40 CFR part 51.359. The Illinois submittal contains a general provision under P.A. 88–533 which requires that the State I/M program provide for procedures for certifying test results and for reporting and maintaining relevant data and records. In addition, the RFP requires that the contractor submit to IEPA, on a monthly basis, a file containing detailed data for each vehicle test transaction conducted. The data collection requirements specified in the RFP meet those specified in 40 CFR part 51.365. Once the final I/M contract is submitted to EPA as supplemental information in support of the SIP this section of the I/M SIP can be fully approved. At this time, EPA proposes to conditionally approve this section of the SIP based on the State's April 22, 1996 commitment to submit to EPA as supplemental information in support of the SIP its final signed contract addressing the data collection requirements of 40 CFR part 51.365 within one year of EPA's final conditional approval.

Data Analysis and Reporting 40 CFR 51.366

Data analysis and reporting are required in order to monitor and evaluate the program by the State and EPA. The Federal I/M rule requires annual reports to be submitted to EPA that provide information and statistics and summarize activities performed for each of the following programs: Testing, quality assurance, quality control and enforcement. These reports are to be submitted by July of each year and shall provide statistics for the period of January to December of the previous year. A biennial report shall be submitted to EPA that addresses changes in the program design, regulations, legal authority, program procedures, any weaknesses in the program found during the previous two year period and how these problems will be or were corrected. The Illinois RFP contains the necessary provisions addressing the requirements of this section. However, in order to receive full approval, the State must submit its final, signed contract as supplemental information in support of the SIP addressing the requirements of 40 CFR part 51.366 to EPA within one year of EPA's final conditional approval. EPA proposes to conditionally approve this section of the SIP based on the State's April 22, 1996 commitment to submit to EPA as supplemental information in support of the SIP its final signed contract addressing the data analysis and reporting requirements of 40 CFR part 51.366 within the time frame specified above.

Inspector Training and Licensing or Certification 40 CFR 51.367

The Federal I/M regulation requires all inspectors to be formally trained and licensed or certified to conduct inspections. The Illinois P.A. 88–533 requires all inspectors to be certified by IEPA after successfully completing a course of training and successfully passing a written test. The RFP requires Bidders to include in their Technical Proposal a detailed Management Plan for the implementation and operation of the contracted elements of the Illinois enhanced I/M program. The Management Plan must include as part of its elements, a description of the Personnel Training and Certification Program as described in the RFP. The RFP requires the Contractor to establish and operate an on-going program to train and certify contractor and IEPA personnel. EPA proposes to conditionally approve this section of the SIP based on the State's April 22, 1996 commitment to submit to EPA as supplemental information in support of the SIP its final signed contract and the contractor's Management Plan addressing the requirements of 40 CFR part 51.367 within one year of EPA's final conditional approval.

Public Information and Consumer Protection 40 CFR 51.368

The Federal I/M regulation requires the SIP to include a public information and consumer protection programs. The submittal needs to include a public information program, which educates the public on I/M, State, and Federal regulations, air quality, the contribution of motor vehicles to the air pollution problem, and other items as describe in the Federal rule. A consumer protection program, which includes provisions for a challenge mechanism, protection of whistle blowers and assistance to motorists in obtaining warranty covered repair, will also need to be addressed. The Illinois submittal contains the legal authority establishing grievance procedures for consumers to use, but it does not address the rest of the requirements stated above for this section. In order to receive full approval, the State has committed in IEPA's April 22, 1996, letter to submit the remaining provisions of the public information program within one year from EPA's final conditional approval. EPA proposes to conditionally approve this portion of the SIP based on the State's commitment to address the requirements of this section within the time frame stated above.

Improving Repair Effectiveness 40 CFR 51.369

Effective repairs are the key to achieving program goals. The Federal regulation requires states to take steps to ensure that the capability exists in the repair industry to repair vehicles. The SIP must include a description of the technical assistance program to be implemented, a description of the procedures and criteria to be used in meeting the performance monitoring requirements required in the Federal regulation and a description of the repair technician training resources available in the community. The Illinois submittal does not contain any provisions addressing the requirements of this section, however the State has submitted a commitment to address the requirements of this section, including the submittal of a description of available technician training resources, within one year of EPA's final conditional approval. EPA is proposing to conditionally approve this portion of the State submittal based on the State's commitment to submit the necessary documentation to EPA in the time frame stated above.

Compliance With Recall Notices 40 CFR 51.370

States are required to establish a method to ensure that vehicles subject to enhanced I/M and that are included in either a voluntary emissions recall as defined at 40 CFR 85.1902(d), or in a remedial plan determination made

pursuant to section 207(c) of the Act, receive the required repairs prior to completing the emission test or renewing the vehicle registration. The Illinois P.A. 88–533 provides the legal authority to require owners to comply with emission related recalls before completing the emission test. The Illinois RFP requires that the contractor provide and maintain as part of the data handling system a means to identify vehicles with unresolved emissions recalls based upon the data provided by EPA. At a minimum, the Contractor and IEPA will have the capability to store, retrieve, and update recall data that consists of the VIN, the numbers of the recall campaign, and the date that the repairs were performed. The system is to be capable of interactively updating vehicle and/or recall database records based upon information supplied by vehicle owners indicating that required repairs have been made. The system will also be capable of updating appropriate records based upon updated data provided by EPA. EPA proposes to approve this section of the SIP based on the State's April 22, 1996 commitment to submit to EPA as supplemental information in support of the SIP its final signed contract addressing the annual reporting requirements of 40 CFR part 51.370 within one year of EPA's final conditional approval.

On-Road Testing 40 CFR 51.371

On-road testing is required in enhanced I/M areas. The use of either remote sensing devices (RSD) or roadside pullovers including tailpipe emission testing can be used to meet the Federal regulations. The program must include on-road testing of 0.5 percent of the subject fleet or 20,000 vehicles, whichever is less, in the nonattainment area or the I/M program area. Motorists that have passed an emission test and are found to be high emitters as a result of a on-road test shall be required to pass an out-of-cycle test. The Illinois P.A. 88–533 requires on-road testing through the use of remote sensing devices. The SIP submittal requires the use of RSD to test at least 0.5 percent of the subject fleet per year in the I/M program area. The RFP requires that the Contractor develop and maintain written on-road inspection procedures to be approved by IEPA. In addition, the Contractor is to provide and maintain as part of the system on-road testing information containing vehicle and test results obtained from the on-road testing program. The Contractor will be responsible for evaluating all on-road emission data, including linking emissions data with vehicle database records. EPA proposes to conditionally approve this section of the SIP based on the State's April 22, 1996 commitment to submit to EPA as supplemental information in support of the SIP its final signed contract addressing the on-road testing specifications of 40 CFR part 51.371 within one year of EPA's final conditional approval.

Proposed Action

EPA is proposing to approve portions and conditionally approve other portions of this revision to the Illinois SIP for an enhanced I/M program, as cited above. If Illinois fails to timely submit the materials discussed above within one year of EPA's final conditional approval, the final conditional approval will automatically convert to a disapproval.

I. Basis for Conditional Approval

The EPA believes conditional approval is appropriate in this case because the State has the necessary legal authority for an enhanced I/M program and needs only to award the I/M contract and amend current administrative rules to address a number of enhanced I/M program requirements. As a condition of EPA's proposed conditional approval, the State must submit a final signed I/M contract as supplemental information in support of the SIP and any additional material necessary to address the deficiencies identified in this document to EPA no later than one year after EPA's final conditional approval. On April 22, 1996, the IEPA submitted a letter committing to this. In the letter IEPA commits to provide EPA the signed enhanced I/M contract, in addition to provide appropriate analyses, calculations, and rules as discussed in a conference call on April 9, 1996 between IEPA and EPA. The telephone conversation record of this call will be included as part of the Illinois SIP.

II. Statement of Approvability

Under the authority of the Governor of Illinois, the IEPA submitted a SIP revision to satisfy the requirements of the I/M regulation to the EPA on June 29, 1995. EPA found the Illinois SIP complete in a letter dated June 30, 1995. The EPA has reviewed this submittal and is proposing to approve portions and proposing to conditionally approve other portions of it pursuant to Section 110(k) of the Act, on the condition that the portions of the I/M program noted above are adopted and/or submitted on the schedules noted in this proposed rulemaking. If EPA takes final conditional approval on the commitment, the State must meet its commitment to submit the final I/M contract and all other supporting documentation within one year of the conditional approval. Once the EPA has conditionally approved this committal, if the State fails to submit any necessary rules and/or documentation to EPA, final conditional approval will automatically convert to a disapproval. EPA will notify the State by letter to this effect. Once the SIP has been disapproved, these commitments will no longer be a part of the approved nonattainment area SIPs. The EPA subsequently will publish a notice to this effect in the notice section of the Federal Register indicating that the commitment or commitments have been disapproved and removed from the SIP. If the State adopts and submits the final rule amendments and the final I/M contract, as supplemental information in support of the SIP, to EPA within the applicable time frame, the conditionally approved commitments will remain part of the SIP until the EPA takes final action approving or disapproving the new submittal. If the EPA approves the subsequent submittal, those newly approved rules and/or documentation will become part of the SIP.

If after considering the comments on the proposal, the EPA issues a final disapproval or if the conditional approval portions are converted to a disapproval, the sanctions clock under section 179(a) will begin. If the State does not submit and EPA does not approve the rule on which any disapproval is based within 18 months of the disapproval, the EPA must impose one of the sanctions under section 179(b)-highway funding restrictions or the offset sanction. In addition, any final disapproval would start the 24 month clock for the imposition of a section 110(c) Federal Implementation Plan. Finally, under section 110(m) the EPA has discretionary authority to impose sanctions at any time after a final disapproval.

Regulatory Flexibility

Under the Regulatory Flexibility Act, 5 U.S.C. 600 et seq., EPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C. 603 and 604. Alternatively, EPA may certify that the rule will not have a significant impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

SIP approvals under 110 and subchapter I, Part D of the CAA do not

create any new requirements, but simply approve requirements that the State is already imposing. Therefore, because the Federal SIP approval does not impose any new requirements, I certify that it does not have a significant impact on any small entities affected. Moreover, due to the nature of the Federal-state relationship under the CAA, preparation of a regulatory flexibility analysis would constitute Federal inquiry into the economic reasonableness of state action. The CAA forbids EPA to base its actions concerning SIPs on such grounds. *Union Electric Co.* v. *U.S. E.P.A.*, 427 U.S. 246, 256–66 (S.Ct. 1976); 42 U.S.C. 7410(a)(2) and 7410(k)(3).

Section 202 of the Unfunded Mandates Reform Act of 1995 (''Unfunded Mandates Act'') (signed into law on March 22, 1995) requires that the EPA prepare a budgetary impact statement before promulgating a rule that includes a Federal mandate that may result in expenditure by State, local, and tribal governments, in aggregate, or by the private sector, of $100 million or more in any one year. Section 203 requires the EPA to establish a plan for obtaining input from and informing, educating, and advising any small governments that may be significantly or uniquely affected by the rule.

Under section 205 of the Unfunded Mandates Act, the EPA must identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a budgetary impact statement must be prepared. The EPA must select from those alternatives the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule, unless the EPA explains why this alternative is not selected or the selection of this alternative is inconsistent with law.

Because this proposed rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less then $100 million in any one year, the EPA has not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, the EPA is not required to develop a plan with regard to small governments. It imposes no additional requirements. The Office of Management and Budget has exempted this action rule from Executive Order 12866 review.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Nitrogen Oxide, Ozone, Volatile Organic Compound.

Authority: 42 U.S.C. 7401–7671q.

Dated: April 29, 1996.

David A. Ullrich,

Acting Regional Administrator.

[FR Doc. 96–11758 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

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40 CFR Part 52

[WI67–01–7276; FRL–5501–5]

Approval and Promulgation of Implementation Plan; Wisconsin

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This notice proposes approval of a revision to the Wisconsin State Implementation Plan (SIP) to meet the requirements of the EPA transportation conformity rule set forth at 40 CFR part 51 subpart T—Conformity to State or Federal Implementation Plans of Transportation Plans, Programs, and Projects Developed, Funded or Approved Under Title 23 U.S.C. or the Federal Transit Act. The transportation conformity SIP revision will enable the State of Wisconsin to implement and enforce the Federal transportation conformity requirements at the State or local level in accordance with 40 CFR 51.396(b). This notice of approval is limited only to 40 CFR part 51, subpart T (transportation conformity). SIP revisions submitted under 40 CFR part 51, subpart W, relating to conformity of general Federal actions, will be addressed in a separate EPA notice. This notice provides the rationale for the proposed approval and other information.

DATES: Comments on this proposed action must be received by June 10, 1996.

ADDRESSES: Written comments should be sent to: Carlton T. Nash, Chief, Regulation Development section, Air Programs Branch (AR–18J), USEPA, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604–3590. Copies of the SIP revision, public comments and EPA's responses are available for inspection at the following address: United States Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. (It is recommended that you telephone Michael Leslie at (312) 353–6680 before visiting the Region 5 Office.)

A copy of this SIP revision is available for inspection at the following location: Office of Air and Radiation (OAR) Docket and Information Center (Air Docket 6102), room M1500, United States Environmental Protection Agency, 401 M Street S.W., Washington, D.C. 20460, (202) 260–7548.

FOR FURTHER INFORMATION CONTACT: Michael G. Leslie, Regulation Development Section (AR–18J), Air Programs Branch, Air and Radiation Division, United States Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, Telephone Number (312) 353–6680.

SUPPLEMENTARY INFORMATION:

I. Background

Section 176(c) of the Clean Air Act (CAA), 42 U.S.C. § 7506(c), provides that no Federal department, agency, or instrumentality shall engage in, support in any way or provide financial assistance for, license or permit, or approve any activity which does not conform to a SIP which has been approved or promulgated pursuant to the CAA. Conformity is defined as conformity to the SIP's purpose of eliminating or reducing the severity and number of violations of the National Ambient Air Quality Standards and achieving expeditious attainment of such standards, and that such activities will not: (1) Cause or contribute to any new violation of any standard in any area, (2) increase the frequency or severity of any existing violation of any standard in any area, or (3) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area.

Section 176(c)(4)(A) of the CAA requires EPA to promulgate criteria and procedures for determining conformity of all Federal actions (transportation and general) to applicable SIPs. The EPA published the final transportation conformity rules in the November 24, 1993, Federal Register and codified them at 40 CFR part 51 subpart T—Conformity to State or Federal Implementation Plans of Transportation Plans, Programs, and Projects Developed, Funded or Approved Under Title 23 U.S.C. or the Federal Transit Act. The conformity rules require States and local agencies to adopt and submit to the EPA a transportation conformity SIP revision not later than November 24, 1994. This notice does not address the conformity requirements applicable to general Federal actions which are set forth at 40 CFR part 51 subpart W. The EPA will take action on SIP revisions

relating to those requirements in a separate notice.

II. Evaluation of the State's Submittal

Pursuant to the requirements under section 176(c)(4)(C) of the CAA, the Wisconsin Department of Natural Resources (WDNR) submitted a SIP revision to the EPA on November 23, 1994, and supplemented this submittal on June 14, 1995. In its submittal, the State included provisions required by the EPA transportation conformity rule (40 CFR part 51, subpart T), and Memoranda of Agreements (MOA) between the affected agencies.

Transportation conformity is required for all areas which are designated nonattainment or maintenance for any transportation related criteria pollutants. The State of Wisconsin currently has 11 counties designated as nonattainment for ozone. The areas for which transportation conformity determinations are required and which are included as part of Wisconsin's submittal include the following nonurbanized counties: Door, Keewaunee, and Manitowoc. The urbanized areas include: Milwaukee-Racine Consolidated Metropolitan Statistical Area (MSA) (Kenosha, Milwaukee, Ozaukee, Racine, Walworth, Washington, and Waukesha Counties), and Sheboygan MSA (Sheboygan County).

The WDNR held a public hearing on its transportation conformity submittal on January 11 and 12, 1995. Minor modifications were made in response to the comments and addressed in the final submittal.

The consultation section of the EPA transportation conformity rule (40 CFR 51.402) requires that the SIP revision include procedures for interagency consultation among the Federal, State, and local agencies and for resolution of conflicts in accordance with the criteria set forth in 40 CFR 51.402. Specifically, the SIP revision must include processes and procedures to be undertaken by Metropolitan Planning Organizations (MPO), State departments of transportation, and the United States Department of Transportation (USDOT) with State and local air quality agencies and EPA before making a conformity determination, and by State and local air quality agencies and EPA with MPOs, State departments of transportation, and USDOT in developing applicable SIPs.

In order to satisfy these requirements, the WDNR developed an ad hoc multi-agency committee, which included representatives from the WDNR, Wisconsin Department of Transportation (WDOT), USDOT, and MPOs. This group developed the final consultation rule by integrating the requirements of 40 CFR 51.402 and 23 CFR part 450 with the local procedures and processes. Wisconsin's final consultation rule outlines the roles and responsibilities of each of the affected agencies for the process for determining conformity. The consultation rule further outline the procedures for conflict resolution in the transportation conformity process, for implementation of the public participation process, and for the submission of documentation relating to a conformity determination. The conformity SIP revision submitted by Wisconsin has adequately addressed all provisions of 40 CFR 51.402 and thus meets the EPA SIP requirements.

Section 51.396(c) of the transportation conformity rule states that to be approvable by the EPA, the SIP revision submitted to EPA must address all requirements of the transportation conformity rule in a manner which gives them full legal effect. In particular, the revision must incorporate the provisions of the following sections of the rule in verbatim form, except insofar as needed to give effect to a stated intent in the revision to establish criteria and procedure more stringent than the requirements stated in these sections: 51.392, 51.394, 51.398, 51.400, 51.404, 51.410, 51.412, 51.414, 51.416, 51.418, 51.420, 51.422, 51.424, 51.426, 51.428, 51.430, 51.432, 51.434, 51.436, 51.438, 51.440, 51.442, 51.444, 51.446, 51.448, 51.450, 51.460, and 51.462. The State of Wisconsin submittal incorporated all of the above sections in verbatim form, except for §§ 51.424, 51.434, 51.442, 51.444, and 51.446. The omitted sections apply only to criteria and procedures for localized Carbon Monoxide hot spots, Particulate Matter areas, and Nitrogen Dioxide areas. Noting this, these sections of the transportation conformity rule are not applicable to the State of Wisconsin, which contains nonattainment areas for ozone.

On August 7, 1995, EPA finalized an amendment to section 51.448. It should be noted that additional sections of the conformity rule are scheduled to be amended. The EPA cannot approve sections into the SIP where inconsistencies exist between the submittal and the final rule. After EPA further amends the conformity rule, the State of Wisconsin will be required to update the SIP to address the rule changes.

The WDNR and the WDOT concluded that this SIP revision in the form of a MOA will be enforceable through section 144.31(1)(e) and section 144.371, Wis. Stats. The MOA, which is a binding agreement among the affected agencies, outlined each agency's roles and responsibilities in the transportation conformity process. A total of three MOA were included in the SIP revision; two MOAs between the local MPO, MDOT and MDNR for the two metropolitan areas, and one MOA between WDOT and WDNR for the remaining rural areas.

Section 85.02, Wis. Stats. requires all agencies involved in transportation related activities to follow the recommendations of the WDOT. The WDOT has the authority over the approval of all Transportation Improvement Programs (TIP) and the approval of Federal and State funds for transportation projects, programs, or plans. The WDOT will not approve any MPO TIP that contains a nonconforming project in the State TIP. Furthermore, the WDOT will not approve Federal or State funding for any nonconforming projects, programs, or plans and may withhold moneys for failure to follow conformity procedures.

Section 30.12(4), Wis. Stats., gives the transportation conformity agreements between WDNR and WDOT full legal effect in Wisconsin. This law requires WDOT to follow its agreement with WDNR or be subject to the prohibitions or permit or approval requirements under sections 29.29, 30.11, 30.12, 30.123, 30.195, 30.20, 59.971, 61.351, 62.231, 87.30 and chapters 144 and 147, Wis. Stats.

Section 1.11, Wis. Stats., the Wisconsin Environmental Policy Act, may be enforced by citizens with regard to activities of WDNR and WDOT.

III. EPA Action

The EPA is proposing approval the transportation conformity SIP revision for the State of Wisconsin. The EPA has evaluated this SIP revision and has determined that the State has fully adopted the provisions of the Federal transportation conformity rules in accordance with 40 CFR part 51 subpart T. The appropriate public participation and comprehensive interagency consultations have been undertaken during development and adoption of this SIP revision.

IV. Miscellaneous

A. Applicability to Future SIP Decisions

Nothing in this action should be construed as permitting, allowing or establishing a precedent for any future request for revision to any SIP. The EPA shall consider each request for revision to the SIP in light of specific technical, economic, and environmental factors

and in relation to relevant statutory and regulatory requirements.

B. Executive Order 12866

This action has been classified as a Table 3 action for signature by the Regional Administrator under the procedures published in the Federal Register on January 19, 1989 (54 FR 2214–2225), as revised by a July 10, 1995 memorandum from Mary Nichols, Assistant Administrator for Air and Radiation. The Office of Management and Budget has exempted this regulatory action from E.O. 12866 review.

C. Regulatory Flexibility

Under the Regulatory Flexibility Act, 5 U.S.C. 600 *et seq.*, EPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities (5 U.S.C. 603 and 604). Alternatively, EPA may certify that the rule will not have a significant impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

This approval does not create any new requirements. Therefore, I certify that this action does not have a significant impact on any small entities affected. Moreover, due to the nature of the Federal-State relationship under the Act, preparation of the regulatory flexibility analysis would constitute Federal inquiry into the economic reasonableness of the State action. The Act forbids EPA to base its actions concerning SIPs on such grounds. *Union Electric Co.* v. *U.S. E.P.A.*, 427 U.S. 246, 256–66 (1976).

Under section 202 of the Unfunded Mandates Reform Act of 1995 (''Unfunded Mandates Act''), signed into law on March 22, 1995, the EPA must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in estimated costs to State, local, or tribal governments in the aggregate; or to the private sector, of $100 million or more. Under section 205, the EPA must select the most cost-effective and least burdensome alternative that achieves the objectives of the rule and is consistent with statutory requirements. section 203 requires the EPA to establish a plan for informing and advising any small governments that may be significantly or uniquely impacted by the rule.

The EPA has determined that the approval action promulgated today does not include a Federal mandate that may result in estimated costs of $100 million or more to either State, local, or tribal governments in the aggregate, or to the private sector.

This Federal action approves pre-existing requirements under State or local law, and imposes no new Federal requirements. Accordingly, no additional costs to State, local, or tribal governments, or the private sector, result from this action.

D. Petitions for Judicial Review

Under section 307(b)(1) of the Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 9, 1996. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review, nor does it extend the time within which a petition for judicial review may be filed and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Hydrocarbons, Intergovernmental relations, Ozone, Transportation conformity, Transportation-air quality planning, Volatile organic compounds.

Authority: 42 U.S.C. 7401–7671q.

Dated: April 26, 1996.

David A. Ullrich,

Acting Regional Administrator.

[FR Doc. 96–11759 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

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40 CFR Part 63

[AD–FRL–5503–2]

Hazardous Air Pollutants: Amendment to Regulations Governing Equivalent Emission Limitations by Permit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On May 20, 1994, the Agency promulgated a rule in the Federal Register (59 FR 26429) governing the establishment of equivalent emission limitations by permit, pursuant to section 112(j) of the Clean Air Act (Act). After the effective date of a Title V permit program in a State, each owner or operator of a major source in a source category for which the EPA was scheduled to, but failed to promulgate a section 112(d) emission standard will be required to obtain an equivalent emission limitation by permit. The permit application must be submitted to the Title V permitting authority 18 months after the EPA's missed promulgation date. This action proposes to amend the original Regulations Governing Equivalent Emission Limitations by Permit rule to delay the section 112(j) permit application deadline for all 4-year source categories listed in the regulatory schedule by 180 days until November 15, 1996. This action is needed to alleviate unnecessary paperwork for both major source owners or operators and permitting agencies. Because the changes are merely to delay the permit application deadline for all 4 year source categories, the EPA does not anticipate receiving adverse comments. Consequently the revisions are also being issued as a direct final rule in the final rules section of this Federal Register. If no significant adverse comments are timely received, no further action will be taken with respect to this proposal, and the direct final rule will become final on the date provided in that action.

DATES: *Comments.* Comments must be received on or before June 10, 1996, unless a hearing is requested by May 20, 1996. If a hearing is requested, written comments must be received by June 24, 1996.

Public Hearing. Anyone requesting a public hearing must contact the EPA no later than May 20, 1996. If a hearing is held, it will take place on May 28, 1996, beginning at 10:00 a.m.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate, if possible) to: Air and Radiation Docket and Information Center (6102), Attention Docket No. A–93–32 (see docket section below), Room M–1500, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460. The EPA requests that a separate copy also be sent to the contact person listed below.

Public Hearing. If a public hearing is held, it will be held at the EPA's Office of Administration Auditorium, Research Triangle Park, North Carolina. Persons interested in attending the hearing or wishing to present oral testimony should notify Ms. Yvonne Chandler, U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone (919) 541–5627.

Docket. Docket No. A–93–32, containing the supporting information for the original Regulations Governing Equivalent Emission Limitations by Permit rule is available for public inspection and copying between 8:00

a.m. and 5:30 p.m., Monday through Friday, at the EPA's Air and Radiation Docket and Information Center (6102), 401 M Street, S.W., Washington, D.C. 20460, or by calling (202) 260–7548. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. James Szykman or Mr. Anthony Wayne, Emission Standards Division (MD–13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541–2452 (Szykman) or (919) 541–5439 (Wayne).

SUPPLEMENTARY INFORMATION: If no significant, adverse comments are timely received, no further activity is contemplated in relation to this proposed rule, and the direct final rule in the final rules section of this Federal Register will automatically go into effect on the date specified in that rule. If significant adverse comments are timely received, the direct final rule will be withdrawn, and all public comment received will be addressed in a subsequent final rule. Because the EPA will not institute a second comment period on this proposed rule, any parties interested in commenting should do so during this comment period.

For further supplemental information, the detailed rationale, and the rule provisions, see the information provided in the direct final rule in the final rules section of this Federal Register.

Administrative

A. Regulatory Impact Analysis

This rule was classified ''non-significant'' under Executive Order 12866 and, therefore, was not reviewed by the Office of Management and Budget.

B. Impact on Reporting Requirements

The information collection requirements of the previously promulgated rule for Regulations Governing Equivalent Emission Limitations by Permit were submitted to and approved by the Office of Management and Budget. A copy of this Information Collection Request (ICR) document (OMB control number 2060–0266) may be obtained from Sandy Farmer, OPPE Regulatory Information Division (2136), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, or by calling (202) 260–2740. Today's proposed revisions to the deadline for submittal of section 112(j) permit applications does not affect the information collection burden estimates made previously. Therefore, the ICR has not been revised.

C. Impact on Small Entities

The Regulatory Flexibility Act of 1980 requires the identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. Because this proposed rulemaking imposes no economic impacts, adverse or otherwise, a Regulatory Flexibility Analysis has not been prepared.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small business entities.

D. Reduction of Governmental Burden

Executive Order 12875 (''Enhancing the Intergovernmental Partnership'') is designed to reduce the burden to State, local, and Tribal governments of the cumulative effect of unfunded Federal mandates. The Order recognizes the need for these entities to be free from unnecessary Federal regulation to enhance their ability to address problems they face and provides for Federal agencies to grant waivers to these entities from discretionary Federal requirements. The Order applies to any regulation that is not required by statute and that creates a mandate upon a State, local, or Tribal government. The EPA anticipates that there will be no additional cost burden imposed on State, local, and Tribal governments as a result of today's action. Indeed, the purpose of the action is to reduce unnecessary burden on permitting agencies.

E. Environmental Justice

Executive Order 12898 requires that each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority and low-income populations. Today's action will help ensure timely compliance and the application of consistent regulatory requirements by allowing the section 112(d) MACT standards to become effective without triggering an unnecessary section 112(j) process. Therefore, no adverse human health or environmental effects are anticipated as a result of today's action.

F. Unfunded Mandates

Under Section 202 of the Unfunded Mandates Reform Act of 1995 (''Unfunded Mandates Act''), the EPA must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in estimated costs to State, local, or tribal governments in the aggregate; or to the private sector, of $100 million or more. Under Section 205, the EPA must select the most cost-effective and least burdensome alternative that achieves the objectives of the rule and is consistent with statutory requirements. Section 203 requires the EPA to establish a plan for informing and advising any small governments that may be significantly or uniquely impacted by the rule.

The EPA has determined that the action proposed today does not include a Federal mandate that may result in estimated costs of $100 million or more to either State, local, or tribal governments in the aggregate, or to the private sector. Therefore, the requirements of the Unfunded Mandates Act do not apply to this action.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practices and procedures, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: May 3, 1996.

Carol M. Browner,

Administrator.

[FR Doc. 96–11738 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

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40 CFR Part 81

[AZR92–0004; FRL–5503–8]

Clean Air Act Reclassification; Arizona-Phoenix Nonattainment Area; Carbon Monoxide

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA proposes to find that the Phoenix, Arizona carbon monoxide (CO) nonattainment area has not attained the CO national ambient air quality standard (NAAQS) by the Clean Air Act (CAA) mandated attainment date for moderate nonattainment areas, December 31, 1995. This proposed finding is based on EPA's review of monitored air quality data for compliance with the CO NAAQS. If EPA takes final action on this proposed finding, the Phoenix CO nonattainment area will be reclassified by operation of law as a serious nonattainment area. The intended effect of such a

reclassification would be to allow the State additional time to submit a new State implementation plan (SIP) providing for attainment of the CO NAAQS by no later than December 31, 2000, the CAA attainment deadline for serious CO areas.

DATES: Written comments on this proposal must be received by June 10, 1996.

ADDRESSES: Written comments should be sent to: Wallace Woo, Chief, Plans Development Section, A–2–2, U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105.

The rulemaking docket for this notice, Docket No. 96–AZ–PL–002, may be inspected and copied at the following location between 8 a.m. and 4:30 p.m. on weekdays. A reasonable fee may be charged for copying parts of the docket.

U.S. Environmental Protection Agency, Region 9, Air and Toxics Division, Plans Development Section, A–2–2, 75 Hawthorne Street, San Francisco, California 94105.

Copies of the docket are also available at the State office listed below: Arizona Department of Environmental Quality, Library, 3033 North Central Avenue, Phoenix, Arizona 85012.

FOR FURTHER INFORMATION CONTACT: Jerry Wamsley, A–2–2, Air and Toxics Division, U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105, (415) 744–1226.

SUPPLEMENTARY INFORMATION:

I. Background

A. CAA Requirements and EPA Actions Concerning Designation and Classifications

The Clean Air Act Amendments of 1990 (CAA) were enacted on November 15, 1990. Under section 107(d)(1)(C) of the CAA, each carbon monoxide (CO) area designated nonattainment prior to enactment of the 1990 Amendments, such as the Phoenix area, was designated nonattainment by operation of law upon enactment of the 1990 Amendments. Under section 186(a) of the Act, each CO area designated nonattainment under section 107(d) was also classified by operation of law as either ''moderate'' or ''serious'' depending on the severity of the area's air quality problem. CO areas with design values between 9.1 and 16.4 parts per million (ppm), such as the Phoenix area, were classified as moderate. These nonattainment designations and classifications were codified in 40 CFR part 81. See 56 FR 56694 (November 6, 1991).

States containing areas that were classified as moderate nonattainment by operation of law under section 107(d) were required to submit State implementation plans (SIPs) designed to attain the CO national ambient air quality standard (NAAQS) as expeditiously as practicable but no later than December 31, 1995.[1]

B. Reclassification to a Serious Nonattainment Area

EPA has the responsibility, pursuant to sections 179(c) and 186(b)(2) of the CAA, of determining, within six months of the applicable attainment date whether the Phoenix area has attained the CO NAAQS. Under section 186(b)(2)(A), if EPA finds that the area has not attained the CO NAAQS, it is reclassified as serious by operation of law. Pursuant to section 186(b)(2)(B) of the Act, EPA must publish a notice in the Federal Register identifying areas which failed to attain the standard and therefore must be reclassified as serious by operation of law.

EPA makes attainment determinations for CO nonattainment areas based upon whether an area has two years (or eight consecutive quarters) of clean air quality data.[2] Section 179(c)(1) of the Act states that the attainment determination must be based upon an area's ''air quality as of the attainment date.'' Consequently, EPA will determine whether an area's air quality has met the CO NAAQS by December 31, 1995 based upon the most recent two years of air quality data entered into the Aerometric Information Retrieval System (AIRS) data base.

EPA determines a CO nonattainment area's air quality status in accordance with 40 CFR part 50.8 and EPA policy.[3] EPA has promulgated two NAAQS for CO: an 8-hour average concentration and a 1-hour average concentration. Because there were no violations of the 1-hour standard in the Phoenix area in 1994 and 1995, this notice addresses only the air quality status of the Phoenix area with respect to the 8-hour standard. The 8-hour CO NAAQS requires that not more than one non-overlapping 8-hour average per year per monitoring site can exceed 9.0 ppm (values below 9.5 are rounded down to 9.0 and they are not considered exceedances). The second exceedance of the 8-hour CO NAAQS at a given monitoring site within the same year constitutes a violation of the CO NAAQS.

C. Attainment Date Extensions

If a state does not have the two consecutive years of clean data necessary to show attainment of the NAAQS, it may apply, under section 186(a)(4) of the CAA, for a one year attainment date extension. EPA may, in its discretion, grant such an extension if the state has: (1) Complied with the requirements and commitments pertaining to the applicable implementation plan for the area, and (2) the area has measured no more than one exceedance of the CO NAAQS at any monitoring site in the nonattainment area in the year preceding the extension year. Under section 186(a)(4), EPA may grant up to two such extensions if these conditions have been met.

II. Today's Action

By today's action, EPA is proposing to find that the Phoenix CO nonattainment area has failed to demonstrate attainment of the CO NAAQS by December 31, 1995. This proposed finding is based upon air quality data showing violations of the CO NAAQS during 1994 and 1995.

A. Ambient Air Monitoring Data

The following table lists each of the monitoring sites in the Phoenix CO nonattainment area where the 8-hour CO NAAQS has been exceeded during 1994 and 1995.

[1] The moderate area SIP requirements are set forth in section 187(a) of the Act and differ depending on whether the area's design value is below or above 12.7 ppm. The Phoenix area has a design value below 12.7 ppm. 40 CFR part 81.303.

[2] See generally memorandum from Sally L. Shaver, Director, Air Quality Strategies and Standards Division, EPA, to Regional Air Office Directors, entitled ''Criteria for Granting Attainment Date Extensions, Making Attainment Determinations, and Determinations of Failure to Attain the NAAQS for Moderate CO Nonattainment Areas,'' October 23, 1995 (Shaver memorandum).

[3] See memorandum from William G. Laxton, Director Technical Support Division, entitled ''Ozone and Carbon Monoxide Design Value Calculations'', June 18, 1990. See also Shaver memorandum.

EXCEEDANCES OF 8-HOUR CO NAAQS FOR PHOENIX NONATTAINMENT AREA

Monitoring site	1994		1995	
	Concentration	Date	Concentration	Date
3847 W. Earll Drive	9.6 ppm	12/3	None recorded.	
	10.0 ppm	12/17		
1845 E. Roosevelt Street	9.7 ppm	12/17	None recorded.	
2710 N.W. Grand Avenue			None recorded	
			9.89 ppm	11/23
			10.23 ppm	12/2
			9.5 ppm	12/3
3315 W. Indian School Road	9.7 ppm	12/2	10.1 ppm	12/2
	10.4 ppm	12/3	9.5 ppm	12/3
	10.5 ppm	12/17		

1. 1994 Data

In a March 1995 letter to EPA,[4] Arizona requested that the 1994 exceedances of the CO NAAQS at the West Indian School Road monitoring site be ''flagged'' as affected by ''exceptional events'' as those terms are defined in EPA guidance.[5] In the same letter, the State requested that the December 17, 1994 exceedance at the West Earll Drive monitoring site be invalidated because that monitor had failed an audit. In response, EPA requested more information to evaluate the exceptional event claims at the West Indian School Road monitoring site and disapproved the State's request to invalidate the December 17, 1994 exceedance at the West Earll Drive monitoring site.[6]

In response to EPA's request for more information, on March 25, 1996, the Arizona Department of Environmental Quality (ADEQ) submitted to EPA additional documentation, prepared by the Maricopa Association of Governments (MAG), on the West Indian School Road exceedances.[7] On April 12, 1996, EPA responded to ADEQ's submittal by concluding that MAG's claims that these 1994 exceedances were affected by exceptional events (unusual traffic conditions and air stagnation conditions) were not supported by the submitted documentation. EPA stated that minor traffic accidents are common in any metropolitan area and that air stagnation conditions routinely occur during the CO season in the Phoenix area. See letter from David P. Howekamp, EPA, to Russell Rhoades, ADEQ, April 12, 1996.

Furthermore, as demonstrated in the table above, even if the West Indian School Road exceedances were deemed to be exceptional events and ultimately rejected for use in the Phoenix area's attainment status determination, there would still be two exceedances in 1994 at West Earll Drive since EPA disapproved the State's request to invalidate the December 17, 1994 exceedance. As discussed in section I.B. of this notice, the second exceedance at a given monitoring site in the same year constitutes a violation. Therefore, based on the 1994 data alone, EPA has concluded that the Phoenix area cannot be deemed to have attained the CO NAAQS by December 31, 1995.

2. 1995 Data

As demonstrated by the above table, the monitoring data indicate that Phoenix area recorded violations of the CO NAAQS in 1995 at Grand Avenue (three exceedances) and West Indian School Road (two exceedances). To date, the State has made no claims to EPA that the exceedances recorded at these monitoring sites are invalid for the purpose of determining the area's attainment status. However, EPA is aware that there have been ongoing communications between ADEQ and MAG regarding potential exceptional events claims for all except one of these exceedances (December 3, 1995 at West Indian School Road).[8] MAG has recommended that ADEQ flag all 1995 exceedances at Grand Avenue and the December 2, 1995 exceedance at West Indian School Road as being affected by traffic accidents, freeway ramp closures, meteorological considerations, and other events. In response, ADEQ stated that in order to meet EPA's Exceptional Event Guideline, MAG would have to submit appropriate documentation demonstrating a causal relationship between the events and measured air quality, and referred MAG to EPA's November 27, 1995 letter on the appropriate documentation regarding traffic accidents. EPA concurs with ADEQ's assessment and refers the reader for further detail to the correspondence between MAG and ADEQ.

Based on the MAG/ADEQ correspondence, EPA believes that the 1995 exceedances are valid for use in determining the attainment status of the Phoenix area. EPA is therefore proposing to find, based on the 1994 and 1995 CO violations discussed above, that the area did not attain the CO NAAQS by December 31, 1995. Similarly, because of the 1995 violations, EPA does not believe that the area could qualify for a one year extension of the attainment deadline.[9]

[4] See letter from Edward Z. Fox, Director, Arizona Department of Environmental Quality to David P. Howekamp, Director, Air & Toxics Division, EPA, Region IX, March 31, 1995.

[5] EPA has established criteria and procedures to identify or flag data which may be affected by exceptional events (e.g., structural fires or industrial accidents) in its ''Guideline on the Identification and Use of Air Quality Data Affected by Exceptional Events,'' July 1986. Under the flagging system, state and local air pollution control agencies are responsible for initially identifying and documenting data influenced by exceptional events. These agencies are expected to develop the appropriate background information necessary to support a decision to flag an individual piece of data. The agencies must then submit the information to EPA for concurrence. Flagging a piece of data or data set does not exclude that data from being used for nonattainment designations or classifications. The actual exclusion would only be allowed if, as a result of a public review process, the responsible government agency, in this case EPA, determines that the data are inappropriate for use in a specific regulatory activity.

[6] See letter from David P. Howekamp, Director, EPA, to Russell F. Rhoades, Director, Arizona Department of Environmental Quality, November 27, 1995.

[7] See letter from Russell F. Rhoades, ADEQ, to David Howekamp, EPA, March 25, 1996.

[8] See e.g., letter from Roger A. Herzog, MAG, to Russell F. Rhoades, ADEQ, February 22, 1996; letter from Nancy Wrona, ADEQ, to John DeBolske, MAG, March 29, 1996.

[9] On March 11, 1996, MAG requested that ADEQ flag as affected by exceptional events (unusual traffic conditions and meteorological considerations) CO NAAQS exceedances on January 10 and 13, 1996 at Grand Avenue. See letter from Roger A. Herzog, MAG, to Russell F. Rhoades, ADEQ, March 11, 1996, attached to letter from Russell F. Rhoades to David Howekamp, March 25, 1996. In its March 25, 1996 letter to EPA, ADEQ submitted documentation from MAG in support of these claims. These 1996 exceedances, while lending additional support to EPA's proposed

Continued

B. SIP Requirements for Serious CO Areas

CO nonattainment areas reclassified as serious under section 186(b)(2) of the CAA are required to submit, within 18 months of the area's reclassification, SIP revisions demonstrating attainment of the CO NAAQS as expeditiously as practicable but no later than December 31, 2000. The serious CO area planning requirements are set forth in section 187(b) of the CAA. EPA has issued two general guidance documents related to the planning requirements for CO SIPs. The first is the ''General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990'' that sets forth EPA's preliminary views on how the Agency intends to act on SIPs submitted under Title I of the Act. See generally 57 FR 13498 (April 16, 1992) and 57 FR 18070 (April 28, 1992). The second general guidance document for CO SIPs issued by EPA is the ''Technical Support Document to Aid the States with the Development of Carbon Monoxide State Implementation Plans,'' July 1992.

If the Phoenix area is reclassified to serious, the State would have to submit a SIP revision to EPA that, in addition to the attainment demonstration, includes: (1) a forecast of vehicle miles travelled (VMT) for each year before the attainment year and provisions for annual updates of these forecasts; (2) adopted contingency measures; and (3) adopted transportation control measures and strategies to offset any growth in CO emissions from growth in VMT or number of vehicle trips. See CAA sections 187(a)(7), 187(a)(2)(A), 187(a)(3), 187(b)(2), and 187(b)(1). Upon reclassification, contingency measures in the moderate area plan for the Phoenix area must be implemented.

III. Executive Order (EO) 12866

Under E.O. 12866, 58 FR 51735 (October 4, 1993), EPA is required to determine whether regulatory actions are significant and therefore should be subject to OMB review, economic analysis, and the requirements of the Executive Order. The Executive Order defines a ''significant regulatory action'' as one that is likely to result in a rule that may meet at least one of the four criteria identified in section 3(f), including, under paragraph (1), that the rule may ''have an annual effect on the economy of $100 million or more or adversely affect, in a material way, the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities.''

The Agency has determined that the finding of failure to attain proposed today would result in none of the effects identified in section 3(f). Under section 186(b)(2) of the CAA, findings of failure to attain and reclassification of nonattainment areas are based upon air quality considerations and must occur by operation of law in light of certain air quality conditions. They do not, in-and-of-themselves, impose any new requirements on any sectors of the economy. In addition, because the statutory requirements are clearly defined with respect to the differently classified areas, and because those requirements are automatically triggered by classifications that, in turn, are triggered by air quality values, findings of failure to attain and reclassification cannot be said to impose a materially adverse impact on State, local, or tribal governments or communities.

IV. Regulatory Flexibility

Under the Regulatory Flexibility Act, 5 U.S.C. 601 et seq., EPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C 603 and 604. Alternatively, EPA may certify that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

As discussed in section III of this notice, findings of failure to attain and reclassification of nonattainment areas under section 186(b)(2) of the CAA do not in-and-of-themselves create any new requirements. Therefore, I certify that today's proposed action does not have a significant impact on small entities.

Unfunded Mandates

Under sections 202, 203 and 205 of the Unfunded Mandates Reform Act of 1995 (Unfunded Mandates Act), signed into law on March 22, 1995, EPA must assess whether various actions undertaken in association with proposed or final regulations include a Federal mandate that may result in estimated costs of $100 million or more to the private sector, or to State, local or tribal governments in the aggregate.

Clean Air Act Reclassification; Arizona-Phoenix; Carbon Monoxide 14

EPA believes, as discussed above, that the proposed finding of failure to attain and reclassification of the Phoenix nonattainment area are factual determinations based upon air quality considerations and must occur by operation of law and, hence, do not impose any Federal intergovernmental mandate, as defined in section 101 of the Unfunded Mandates Act.

List of Subjects in 40 CFR Part 81

Environmental protection, Air pollution control, Intergovernmental relations, Carbon monoxide.

Authority: 42 U.S.C. sections 7401–7671q.

Dated: April 29, 1996.

Felicia Marcus,

Regional Administrator.

[FR Doc. 96–11739 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

finding of failure to attain based on the 1994 and 1995 data, are relevant to today's proposal in only one respect. If EPA were to conclude that the Phoenix area qualified for a one year extension of the attainment date, the 1996 exceedances, if validated as a NAAQS violation, would prevent the area from obtaining a second one year extension. As stated above, EPA does not believe the Phoenix area can qualify for the first extension. Moreover, EPA does not believe that the 1996 exceedances were affected by exceptional events. See letter from David P. Howekamp, EPA to Russell Rhoades, ADEQ, April 12, 1996. Therefore, the 1996 data are not addressed further in this notice.

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40 CFR Parts 148, 261, 268, 271

[FRL–5503–4]

RIN 2050–AE05

Land Disposal Restrictions Phase IV Proposed Rule—Issues Associated With Clean Water Act Treatment Equivalency, and Treatment Standards for Wood Preserving Wastes and Toxicity Characteristic Metal Wastes; Notice of Data Availability

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of data availability.

SUMMARY: Since publication of the Land Disposal Restrictions (LDR) Phase IV proposal (60 FR 43654, August 22, 1995), EPA has received additional information which will be considered in developing its final rule. The public has 30 days from publication of this notice to comment on that additional information. Readers should note that only comments about the new information discussed in this notice will be considered during the comment period; issues proposed in the August 22, 1995 Phase IV rule, and in the Phase IV Supplemental Proposal on mineral processing wastes (61 FR 2338, January 25, 1996), that are not discussed in this Notice of Data Availability, are not open for further comment.

DATES: Comments are due by June 10, 1996.

ADDRESSES: To submit comments, the public must send an original and two copies to Docket Number F–96–P42A–

FFFFF, located at the RCRA Docket. The mailing address is: RCRA Information Center, U.S. Environmental Protection Agency (5305W), 401 M. Street, SW, Washington, D.C. 20460. RCRA Information Center is located at 1235 Jefferson Davis Highway, First Floor, Arlington, Virginia. The RCRA Information Center is open for public inspection and copying of supporting information for RCRA rules from 9:00 am to 4:00 pm Monday through Friday, except for Federal holidays. The public must make an appointment to review docket materials by calling (703) 603–9230. The public may copy a maximum of 100 pages from any regulatory document at no cost. Additional copies cost $0.15 per page.

FOR FURTHER INFORMATION CONTACT: For general information or to order paper copies of this Federal Register document, call the RCRA Hotline. Callers within the Washington, Metropolitan Area must dial 703–412–9810 or TDD 703–412–3323 (hearing impaired). Long-distance callers may call 1–800–424–9346 or TDD 1–800–553–7672. The RCRA Hotline is open Monday-Friday, 9:00 a.m. to 6:00 p.m., Eastern Standard Time. For other information on this notice, contact Sue Slotnick (5302W), Office of Solid Waste, 401 M Street, SW, Washington, DC 20460, phone (703) 308–8462.

SUPPLEMENTARY INFORMATION:

Paperless Office Effort

EPA is asking prospective commenters to voluntarily submit one additional copy of their comments on labeled personal computer diskettes in ASCII (TEXT) format or a word processing format that can be converted to ASCII (TEXT). It is essential to specify on the disk label the word processing software and version/edition as well as the commenter's name. This will allow EPA to convert the comments into one of the word processing formats utilized by the Agency. Please use mailing envelopes designed to physically protect the submitted diskettes. EPA emphasizes that submission of comments on diskettes is not mandatory, nor will it result in any advantage or disadvantage to any commenter. This expedited procedure is in conjunction with the Agency ''Paperless Office'' campaign. For further information on the submission of diskettes, contact Sue Slotnick of the Waste Treatment Branch at (703) 308–8462.

This Federal Register notice is available on the Internet System through EPA Public Access Server at gopher.epa.gov.or through WWW.epa.gov. For the text of the notice, choose: Rules, Regulations, and Legislation; the FR-Waste; finally, Year/Month/Day.

Notice of Data Availability

On August 22, 1995, EPA proposed the LDR Phase IV rule (60 FR 43654), containing proposed treatment standards for newly listed and characteristic wastes, among other issues. In a supplemental proposal (61 FR 2338, January 25, 1996), EPA proposed treatment standards and changes to the definition of solid waste for mineral processing wastes. The two proposals will form the basis for a single rule due to be promulgated later this year, referred to as the Phase IV final rule. Today's Notice of Data Availability pertains primarily to the original Phase IV proposal of August 22, 1995. Also, some possible changes discussed in this notice could affect the Universal Treatment Standards for metals in general, and could affect the current treatment standard for F024. Finally, additional comments on capacity for treating mineral processing wastes are solicited.

Since publication of the Phase IV proposal, EPA has received comments and data, available in RCRA docket number F–95–PH4P–FFFFF, on many issues, including the following:

(1) Treatment standards for toxicity characteristic (TC) metal wastes;

(2) Treatment standards for wood preserving wastes;

(3) Solid waste exclusion for recycled wood preserving wastewaters; and,

(4) Capacity issues.

These issues, and a discussion of the data the Agency has received on each issue, are presented below.

(1) Treatment Standards for Toxicity Characteristic (TC) Metal Wastes

a. Lead-Bearing Smelter Wastes

Comments were received from several trade organizations (see comments from Swidler & Berlin for the Association of Battery Recyclers, PH4P–00038; Battery Council International, PH4P–00045; Collier, Shannon, Rill & Scott, PH4P–00077; and, Resource Consultants, PH4P–00078.A), expressing concern about the proposed application of Universal Treatment Standard to metal TC wastes generated from the recycling of lead-acid batteries (lead slags and sludges containing lead).

The Resource Consultants comment contained limited data which included concentrations of lead, selenium, and barium in untreated and treated (stabilized) secondary lead smelter slag and soils. These data may indicate that their stabilized lead smelter slag cannot achieve the Universal Treatment Standard limits. In addition, limited data were submitted to show how these lead wastes differ in composition from K061. These data will be further assessed by the Agency to determine whether they may be used to revise the treatment standards for these constituents, or to identify particular treatability groups for which revised treatment standards may be promulgated. The Agency is also reviewing data submitted by the Exide Corporation on HTMR for the treatment of lead slags.

In addition, the Agency is reviewing information from East Penn Manufacturing Company, Inc., that seems to indicate that slag can be returned to the furnace until the metals are no longer present at hazardous concentrations. (If slag is reclaimed, it is not a solid waste during the reclamation process because it is a ''byproduct'' under 40 CFR 261.2(c). If the resulting discarded slag is below the toxicity characteristic levels, the slag is not a hazardous waste and so would not be subject to the LDRs.)

EPA also at this time wishes to clarify an issue raised with respect to the applicability of the Land Disposal Restriction Standards to slags resulting from smelting of lead acid batteries. The LDR standard for lead acid batteries is specified as RLEAD, or recovery of lead. (See 40 CFR Section 268.42.) Once the batteries are smelted, the LDR requirements have been satisfied, and therefore the slag resulting from this smelting need not be treated further. The standards proposed under Phase IV (i.e., compliance with UTS) would not apply to this slag, even if the slag exhibits a characteristic of hazardous waste. (However, if the slag exhibits a characteristic of hazardous waste, it must of course be managed under all other applicable, i.e., non-LDR, hazardous waste requirements.) EPA notes also that if a secondary smelter accepts materials other than lead acid batteries, then LDR requirements could apply to the slag, as with any other waste. The Agency understands, however, that secondary lead smelters routinely accept some materials closely related to lead acid batteries. EPA does not think that LDR status of the slags should be affected by these additional, but closely related lead-bearing items, i.e., the slag would remain exempt from LDR requirements. The Agency requests comment on this issue. EPA dealt with a very similar issue in the Boiler and Industrial Furnace (BIF) regulations (see 56 FR 42517, August 27, 1991). In that rule, the Agency published a list of

materials that secondary lead smelters may process and still remain exempt from the BIF regulations, codified at 40 CFR Part 266, Appendix XI. The Agency requests comment on using this same list for purposes of defining those materials secondary smelters may accept without changing the LDR status of their resulting slags.

b. Lead-Bearing Foundry Wastes

The metal foundry industry generates emission control dust and foundry sand containing cadmium, chronium, lead and selenium. The American Foundryman's Society submitted comments to the Phase IV Rule stating that foundry sand is different from K061 and that HTMR is not demonstrated or available, and stabilization has not been demonstrated as meeting Universal Treatment Standards for foundry sands. The comments referred the Agency to data which the Agency is now reviewing.

c. Treatment Standard for D011 Silver TC Wastes

EPA is considering alternative options for the treatment standard for D011. In comments to the Phase IV rule, the Silver Coalition and the Eastman Kodak Company each stated that silver should be removed from the Toxicity Characteristic list of constituents, based on low risk, or at least EPA should not promulgate a treatment standard for silver below the TC level of 5.0 mg/l. The regulation of silver as a TC metal is indeed a subject of concern for EPA. While human health effects are not major, concern about aquatic toxicity remains. The Agency is not yet prepared to make a decision on the removal of silver from the TC list (at 40 CFR 261.24). However, given the low risk to human health, EPA is considering two possibilities for the treatment standard, in addition to the proposed treatment standards of 0.43 mg/l for wastewaters and 0.30 mg/l TCLP for nonwastewaters. One new option is to revise the Universal Treatment Standard for silver at a higher value, e.g. the TC regulatory level of 5.0 mg/l. This change would affect all wastes subject to UTS. The second option is to set the standard for D011 at the higher level, maintaining the current Universal Treatment Standard levels for all other wastes containing silver as a regulated constituent. Comments are requested on these two new options.

(2) Treatment Standards for Wood Preserving Waste F032, and Potentially, F024

EPA proposed in the Phase IV proposal to require wood preserving waste F032 to meet the Universal Treatment Standard for a specific list of hazardous constituents (see 60 FR 43680; August 22, 1995, and its Correction Notice, 60 FR 546451, October 25, 1995). The F032 constituents include dioxin and furan (D/F) constituents (Id. at 43681). Most comments on the proposed treatment standards for F032 centered on the need to establish numeric limits for D/F as a means to ensure proper treatment. As described below, EPA also received new data. The Agency requests comment on the new data, and on options presented below. Also, commenters should note that a change in the proposed treatment standard for F032 may dictate changes in the F024 (a group of chlorinated aliphatic wastes) treatment standard (see 55 FR 22580–22581, June 1, 1990), as discussed below.

The Penta Task Force's comment (which also included a characterization study from Vulcan Chemicals) and the comment from the American Wood Preserving Institute (AWPI) expressed concerns that promulgation of concentration limits for D/F hazardous constituents in F032 may discourage commercial incineration facilities from treating this waste. As a result of this concern, commenters have asked EPA to consider alternatives to setting D/F concentration limits in its final rule. The Agency is considering options that would provide F032 generators flexibility, provided that adequate treatment of the waste is still ensured. Comments are requested on the options and information discussed below. Under all the options discussed below, the treater would still have to measure compliance with the proposed Universal Treatment Standard levels for the non-D/F constituents in the waste.

New Option: Alternative Treatment Standard

This option calls for EPA to establish an alternative treatment standard that sets incineration as a treatment method for D/F constituents, in lieu of actually measuring the D/F concentrations in the treated residues. F032 wastes treated via incineration would have met the treatment standard for D/F, and disposal would be allowed so long as the Universal Treatment Standard limits promulgated for other organic constituents were also met. Under this option, Treatment Standard levels for each D/F constituent would still be codified so that compliance with these levels can be monitored in cases when F032 is treated by nonincineration technologies.

This option, suggested by the Penta Task Force and AWPI, is patterned after a treatment standard promulgated for F024. The commenters believe that the concentrations of D/F in untreated F032 are similar to those found in untreated F024, therefore, these two wastes can be adequately regulated in a similar manner.

a. Preliminary Review of Vulcan's Characterization Study.

Vulcan Chemical submitted a characterization study in an attachment to the Penta Task Force's comment. This commenter pointed out that the commercial grade tolerances of pentachlorophenol (PCP) allowed domestically have D/F levels well below than those EPA reported in the Listing Background Document for F032, F034, and F035. The commenters also submitted data on D/F measured in several F032 waste streams from six wood preserving plants (see comment number PH4P–00032.J). EPA is currently reviewing these characterization data, however, they appear to support Vulcan and AWPI's claim that D/F concentrations in F032 have been reduced in commercial oils and subsequently, in F032 wastes.

The new F032 characterization data do not appear to support a determination that F032 and F024 are exactly alike. F024 has the following D/F maximum concentrations: up to 2 ppb for penta-PCDD, 10 ppb for hexa-PCDD, 10 ppb of tetra-PCDF, 30 ppb for penta-PCDF, 50 ppb for hexa-PCDF, and tetra-PCDD was not detected above 1 ppb. It appears that F032 may have concentrations of D/F of up to 4.3 ppb for tetra-PCDD, 590 ppb for hexa-PCDD, 78 ppb for penta-PCDF(estimated), 1,500 ppb for hexa-PCDF, and penta-CDD was not detected. Based on these data, it appears that the maximum concentrations of penta-PCDD, tetra-PCDF, and penta-PCDF in F032 are within the same or lower order of magnitude as those in F024. In contrast, tetra-PCDD and hexa-PCDF maximum concentrations in F032 diverge by two orders of magnitude with those in F024. Also, hexa-PCDD maximum concentrations in F032 may exceed by one order of magnitude those found in F024. However, neither of these wastes were identified as 'acutely toxic' in 40 CFR 261, Subpart D, so in this sense they are in a similar class.

b. Feasibility of setting ''INCIN'' or ''CMBST'' as an Alternative Treatment Standard

In spite of some differences between these two wastes, EPA believes that a treatment standard allowing incineration (or 'combustion,' see discussion below) as an alternative

standard for D/F in F032 may be technically feasible. One reason is that incineration is BDAT for dioxin-containing wastes. EPA also believes that incineration, and in fact, combustion technologies generally, are among the least matrix-dependant technologies capable of treating the diverse range of residues that comprise F032. Various types of incineration have been demonstrated to treat high and low level D/F constituents below detection limits in incineration residues.

Suboptions under consideration. EPA has identified, however, three regulatory suboptions for the implementation of Vulcan's proposed alternative treatment method. Each suboption is discussed below. The Agency notes that suboptions 2 and 3 would also change the F024 treatment standard. Also, suboptions 2 and 3 are not mutually exclusive, and both could be selected by the Agency.

Suboption 1: Apply existing F024 alternative combustion treatment standard to F032.

The treatment standard for F024 was originally limited to incineration units. In the Phase III final rule (April 8, 1996), EPA amended the incineration treatment standard (see 40 CFR 268.42, Table 1, 'INCIN') to include additional combustion devices (see 'CMBST' in the Phase III final rule). EPA believes that well-operated and well-designed combustion units can meet the treatment standard for F024 and F032. Setting CMBST as the treatment standard for D/F in F032 would allow wider access to a variety of combustion practices.

Suboption 2: Establish F032's and revise F024's CMBST alternative standard to require the combustion unit to achieve a dioxin emission standard. One concern with the CMBST treatment standard is that D/F can be reformed in the post-combustion zone if favorable conditions exist. Thus, controls may be needed to minimize the potential for forming and emitting D/F emissions into the atmosphere, and to minimize the potential for such products of incomplete combustion to be adsorbed onto wastes. The Agency is concerned that until combustion units are regulated under the proposed MACT standards discussed below, a simple CMBST standard for either F024 or F032 could actually lead to increased air emissions of D/F, or increased concentrations adsorbed onto combustion wastes, if these F024 and F032 wastes were combusted in units that foster the formation of D/F. (It also must be remembered that treatment standards that result in unsafe cross-media transfers of pollutants do not satisfy the requirements of RCRA section 3004(m)). See *Chemical Waste Management* v. *EPA*, 976 F. 2d 2, 17 (D.C. Cir. 1992).) Studies (see discussion below) show that effective controls to inhibit D/F formation may include one or more of the following: (1) rapid quench of combustion gases; (2) air pollution control device's inlet temperatures of less than 400 F for the flue gas; (3) good combustion practices (e.g. like higher temperatures, proper mixing in the combustion zone, and appropriate chemical residence time); and, finally, (4) activated carbon injection scrubbing, if dioxin emissions remain high.

Based on studies conducted at various domestic incineration units such as light weight aggregate kilns and cement kilns, EPA has proposed regulations that set a maximum toxicity equivalent (TEQ) D/F emission standard of 0.20 ng/DSCF (corrected to 7% O_2) for combustion units burning RCRA hazardous wastes. (See Proposed Rule (signed March 20, 1996)—Revised Technical Standards Waste Combustion Facilities (http://www.epa.gov/epaoswer/combust.html.) EPA's studies show that at least 50% of the facilities tested for the proposed combustion rule meet this MACT limit. EPA is requesting comments on whether this D/F emission standard should also be codified as a requirement of a CMBST alternative treatment standard. [For background information regarding the development and implementation of such an air emission standard, see the following documents: (1) Proposed Rule (signed March 20, 1996)—Revised Technical Standards Waste Combustion Facilities http://www.epa.gov/epaoswer/combust.html); (2) Draft Technical Support Document for HWC MACT Standards, Volume III: Selection of MACT Standards and Technologies,(see pages 5–1 through 5–6); (3) Combustion Emission Technical Resource Document (CETRED) (see pages A–54 through A–56) (OSW: EPA 530–R–94–014, May 1994); and, (4) Performance of activated carbon injection on dioxin/furan and mercury emissions, February 23, 1996, memorandum from Shiva Garg of EPA's OSW to DOCKET # F–96–RCSP–FFFFF.] Compliance would have to be documented at least every 18 months.

Under this suboption, any RCRA permitted or interim status combustion device capable of demonstrating achievability in meeting the dioxin (TEQ) air emission discharge limit would be allowed to combust F032 and F024. Should EPA ultimately select a standard other than 0.2 ng/DSCF, the Agency would of course revisit the LDR standard for F024 and F032.

Suboption 3: Revise F024's CMBST alternative standard (and set F032's standard) to limit the combustion of F024 and F032 to combustion devices that have been permitted. A final option would be to limit combustion of F024 and F032 to combustion devices (i.e., incinerators, boilers, and industrial furnaces) that have been evaluated as part of the RCRA permitting process, including potential evaluation under the omnibus permitting authority set out in RCRA section 3005(c)(3). This could involve a site-specific evaluation of whether permit conditions more stringent than those required by the regulations are necessary to assure that the facility's combustion practices are sufficiently controlled to be protective of human health and the environment. Since only permitted facilities are subject to omnibus evaluation, this option would necessarily limit the eligible combustion devices to those that have received permits.

A complete list of related references is available in the RCRA docket for this notice. It is called 'Reference List for F032.'

(3) Solid Waste Exclusion of Recycled Wood Preserving Wastewaters

In the Phase IV proposal, EPA announced that it would consider granting a conditional exclusion from the definition of solid waste for recycled process wastewaters used in the wood preserving industry, provided that the Agency received adequate information to grant such an exclusion. The proposal solicited this information, and specified that it would have to be sufficient to make an industry-wide determination that the reclamation operation was an essential part of production, and that the secondary materials being reclaimed were not likely to be a part of the waste disposal problem.

In response to this solicitation for information, comments were submitted from the American Wood Preservers Institute (AWPI), the State of Oregon Department of Environmental Quality, Universal Forest Products, Inc., Remediation Technologies, Inc., J.H. Baxter & Company, the Environmental Defense Fund (EDF), Beazer East, Inc., and Covington & Burling, pertaining to a possible solid waste exclusion for recycled wood preserving wastewaters. EPA will review this information to determine whether this information is adequate.

Specifically, EPA will be reviewing these comments to evaluate the extent to which they establish that the reclamation of production wastewaters

from the wood preserving industry meet the variance criteria found in 40 CFR 260.31(b). As was stated in the Phase IV proposal, if these criteria can be demonstrated on an industry-wide basis, the Agency may grant a conditional exclusion from the definition of solid waste for reclaimed production wastewaters from the wood preserving industry. The comments from AWPI address each of the 40 CFR 261.31(b) criteria in some detail. EPA will also review other comments, such as those submitted by EDF, that question the basis and desirability of granting the variance on an industry-wide basis. EPA solicits replies to these particular comments.

EPA has also added to the docket a bill being considered by Congress that would exempt from regulation wastewaters provided the materials are ''contained, collected, and reused in an on-site production process that prevents releases to the environment.'' In discussions of this issue, representatives of the American Wood Preservers Association stated that they were not seeking to eliminate the existing Subpart W standards for drip pads used to collect and manage drippage from wood preserving. EPA solicits comments on whether the record supports a national exclusion from the definition of solid waste for recycled process wastewaters from wood preserving operations that are returned to the process from which they originated, with the condition that drippage from the wood is collected and managed on drip pads that are in compliance with Subpart W drip pad standards and that there is no release of the wastewaters to the environment.

(4) Capacity Issues

a. Request for More Information on Amounts of TC Metal Wastes and TC-contaminated Soil

EPA has received comments on the Phase IV proposed rule stating that application of Universal Treatment Standards to TC metal wastes will significantly increase the demand for, and costs of, treatment. As stated in the Supplemental Proposal on mineral processing wastes, EPA has limited information on quantities of TC metal wastes with which to analyze available treatment capacity. Comments also indicated that there may be TC metal-contaminated soil that would require treatment to meet LDR treatment standards. These commenters argue that there will be a need for a capacity variance for TC metal-contaminated soils. Commenters submitted very little data, however, to support their arguments. EPA requests data to potentially support capacity variances for TC metal wastes and TC metal-contaminated soils.

Furthermore, as stated in the Supplemental proposal, EPA solicits information on quantities of characteristic mineral processing wastes, in order to determine whether adequate capacity exists to treat these wastes (61 FR 2360). Because data do not exist to support a capacity variance at this time, EPA is once again urging commenters to provide information on the quantities, characteristics, and management of the newly identified mineral processing wastes.

b. Potential Capacity Variance for FMC Corporation

Representatives of FMC Corporation met with EPA to present their argument that they need a two-year national capacity variance for three large volume TC metal wastewater streams (Medusa Scrubber Blowdown, Anderson Filter Media Rinsate, and Furnace Building Washdown) that are generated at its Pocatello, Idaho facility. (A memorandum summarizing this meeting is part of the record for this rulemaking.) FMC believes that these three wastewaters pose unique treatability problems because of elemental phosphorous contamination and naturally occurring radioactive material. They argue that the logistics and costs to ship these wastestreams off-site for treatment are impractical and prohibitive. FMC also stated that a survey of off-site treatment facilities shows that no permitted TSDF can currently handle these wastestreams. As such, FMC believes it will need a two-year national capacity variance to develop and construct treatment capacity for these wastewater streams and thus comply with Phase IV. FMC intends to submit detailed documentation supporting its claim for a two-year national capacity variance. If it is submitted in a timely fashion, EPA will make it available to the public during the comment period for this notice, and will potentially use this information in determining whether a capacity variance is needed.

Summary

In conclusion, the Agency is making available to the public new data it has received since the Phase IV proposal (or alerting the public to data it expects to receive immediately). Comments are requested on the data and their possible use, as discussed in this notice. In addition, the Agency is requesting data on TC metal wastes, TC metal-contaminated soil, and mineral processing wastes and contaminated soils, that could be used to determine the need for capacity variances, since the Agency currently lacks such data.

Dated: May 3, 1996.

Michael Shapiro,

Director, Office of Solid Waste.

[FR Doc. 96–11740 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

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40 CFR Part 300

[FRL–5502–2]

National Oil and Hazardous Substances Pollution Contingency Plan; National Priorities List

AGENCY: Environmental Protection Agency.

ACTION: Notice of Intent to Delete the Marathon Battery Company site from the National Priorities List: Request for Comments.

SUMMARY: The Environmental Protection Agency (EPA) Region II announces its intent to delete the Marathon Battery Company site from the National Priorities List (NPL) and requests public comment on this action. The NPL is Appendix B of 40 CFR part 300 which is the National Oil and Hazardous Substances Pollution Contingency Plan (NCP), which EPA promulgated pursuant to Section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), as amended. EPA and the State of New York have determined that no further cleanup by responsible parties is appropriate under CERCLA. Moreover, EPA and the State have determined that CERCLA activities conducted at the Marathon Battery Company site to date have been protective of public health, welfare, and the environment.

DATES: Comments concerning the deletion of the Marathon Battery Company site from the NPL may be submitted on or before June 7, 1996.

ADDRESSES: Comments concerning the deletion of the Marathon Battery Company site from the NPL may be submitted to: Pamela Tames, P.E., Remedial Project Manager, U.S. Environmental Protection Agency, Region II, 290 Broadway, 20th floor, New York, NY 10007–1866.

Comprehensive information on the Marathon Battery Company site is contained in the EPA Region II public docket, which is located at EPA's Region II office (the 18th floor), and is available for viewing, by appointment only, from 9:00 a.m. to 5:00 p.m., Monday through Friday, excluding

holidays. For further information, or to request an appointment to review the public docket, please contact Ms. Tames at (212) 637–4255.

Background information from the Regional public docket is also available for viewing at the Marathon Battery Company site's Administrative Record repository located at: Julia Butterfield Memorial Library, Morris Avenue, Cold Spring, NY 10516.

SUPPLEMENTARY INFORMATION:

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I. Introduction
II. NPL Deletion Criteria
III. Deletion Procedures
IV. Basis for Intended Site Deletion

I. Introduction

EPA Region II announces its intent to delete the Marathon Battery Company site from the NPL and requests public comment on this action. The NPL is Appendix B to the NCP, which EPA promulgated pursuant to Section 105 of CERCLA, as amended. EPA identifies sites that appear to present a significant risk to public health, welfare, or the environment and maintains the NPL as the list of those sites. Sites on the NPL may be the subject of remedial actions (RAs) financed by the Hazardous Substances Superfund Response Trust Fund (the ''Fund''). Pursuant to § 300.425(e)(3) of the NCP, any site deleted from the NPL remains eligible for Fund-financed RAs, if conditions at such site warrant action.

EPA will accept comments concerning the Marathon Battery Company site for thirty (30) days after publication of this notice in the Federal Register (until June 7, 1996).

Section II of this notice explains the criteria for deleting sites from the NPL. Section III discusses the procedures that EPA is using for this action. Section IV discusses how the Marathon Battery Company site meets the deletion criteria.

II. NPL Deletion Criteria

The NCP establishes the criteria that the Agency uses to delete sites from the NPL. In accordance with 40 CFR Section 300.425(e), sites may be deleted from the NPL where no further response is appropriate. In making this determination, EPA, in consultation with the State, will consider whether any of the following criteria have been met:

1. That responsible or other persons have implemented all appropriate response actions required; or

2. All appropriate Fund-financed responses under CERCLA have been implemented, and no further cleanup by responsible parties is appropriate; or

3. The remedial investigation has shown that the release poses no significant threat to public health or the environment and, therefore, taking remedial measures is not appropriate.

III. Deletion Procedures

The NCP provides that EPA shall not delete a site from the NPL until the State in which the release was located has concurred, and the public has been afforded an opportunity to comment on the proposed deletion. Deletion of a site from the NPL does not affect responsible party liability or impede agency efforts to recover costs associated with response efforts. The NPL is designed primarily for informational purposes and to assist agency management.

The following procedures were used for the intended deletion of the Marathon Battery Company site:

1. EPA Region II has recommended deletion and has prepared the relevant documents.

2. The State of New York has concurred with the deletion decision.

3. Concurrent with this Notice of Intent to Delete, a notice has been published in local newspapers and has been distributed to appropriate federal, state and local officials, and other interested parties. This notice announces a thirty (30)-day public comment period on the deletion package starting on May 8, 1996 and concluding on June 7, 1996.

4. The Region has made all relevant documents available in the regional office and the local site information repository.

EPA Region II will accept and evaluate public comments and prepare a Responsiveness Summary, which will address the comments received, before a final decision is made. The Agency believes that deletion procedures should focus on notice and comment at the local level. Comments from the local community may be most pertinent to deletion decisions. If, after consideration of these comments, EPA decides to proceed with deletion, the EPA Regional Administrator will place a Notice of Deletion in the Federal Register. The NPL will reflect any deletions in the next update. Public notices and copies of the Responsiveness Summary will be made available to the public by EPA Region II.

IV. Basis for Intended Site Deletion

Site History and Background

The Marathon Battery Company site, located in the Village of Cold Spring, Putnam County, New York, includes a former nickel-cadmium battery manufacturing facility, the Hudson River in the vicinity of the Cold Spring pier, and a series of river backwater areas known as East Foundry Cove, East Foundry Cove Marsh, Constitution Marsh, and West Foundry Cove. Before the site was remediated, a battery plant and an underground asphalt- and clay-lined vault containing spoils from dredging activities in the cove, were located on the facility's grounds. Twenty-nine houses, located on Constitution Drive, are in the vicinity of the site.

Nickel-cadmium batteries were manufactured at the plant from 1952–1979. The plant's wastewater treatment system originally consisted of a lift station and piping for transfer of all process wastewater into the Cold Spring sewer system for discharge directly into the Hudson River at the Cold Spring pier. In addition, a by-pass valve was installed so that when the lift station was shut down or overloaded, a direct gravity discharge could be made into the Kemble Avenue storm sewer for discharge into Foundry Cove.

In the early 1970s, studies conducted by New York University, EPA, and the New York State Department of Environmental Conservation (NYSDEC) showed high levels of cadmium contamination in Foundry Cove sediments. Samples of vegetation and various species of fish, muskrat, turtle eggs, and green heron revealed high concentrations of cadmium, as well.

In 1972, the U.S. Department of Justice signed a Consent Agreement requiring the present and past owners/operators to remove as much cadmium from the outfall area and channel leading into the cove as was economically, technically, and ecologically feasible. The dredge spoils were entombed in the above-described vault. The dredging, however, was not totally successful. Post-dredging monitoring continued to detect elevated cadmium concentrations in the cove's sediments, flora, and fauna. Tidal action slowly flushed some of the remaining cadmium deposits from the cove into the Hudson River and into Constitution Marsh, a National Audubon Society sanctuary.

In October 1981, the Marathon Battery Company site was included on the NPL. In August 1983, EPA and the State of New York signed a Cooperative Agreement to undertake a remedial investigation and feasibility study (RI/FS) at the Marathon Battery Company site. The results of the RI sediment sampling program indicated widespread heavy metal contamination of the sediments and marsh soils of Foundry

Cove. The highest level of contamination occurred in East Foundry Cove Marsh in close proximity to the Kemble Avenue outfall. This area, characterized by a layer of greenish-white sediment spanning an approximately 50 by 100 foot area, showed concentrations as high as 171,000, 156,000, and 6,700 milligrams/kilogram (mg/kg) for cadmium, nickel, and cobalt, respectively. Cadmium levels as high as 2,200 mg/kg were found in the Hudson River in the vicinity of the Cold Spring pier.

Samples from the former battery facility indicated contamination as high as 120,000 mg/kg cadmium and 130,000 mg/kg nickel in the rafters, and up to 600 mg/kg cadmium on the surrounding grounds. Cadmium concentrations up to 67 mg/kg were found in soils in the adjacent residential yards.

In March 1986, NYSDEC requested that EPA assume the lead role for this project. EPA's contractor completed a supplemental RI/FS for the East Foundry Cove Marsh/Constitution Marsh portion of the site (Area I) in August 1986.

On September 30, 1986, a Record of Decision (ROD) was signed for Area I, calling for the dredging of the contaminated sediments exceeding 100 mg/kg, placement of a clay cap and soil cover on the excavated marsh areas, restoration of the marsh, chemical fixation of the excavated sediments, followed by their off-site disposal. Long-term monitoring was selected for Constitution Marsh.

Supplemental RI activities for the former battery facility (Area II) were completed in April 1988. A ROD for this operable unit was signed on September 30, 1988. The selected remedy included decontamination of the interior of the former battery plant building and its contents, excavation and chemical fixation of the dredge spoils vault, excavation and chemical fixation of the cadmium-contaminated soils on the plant grounds and adjacent properties which exceeded 20 mg/kg (determined by a risk assessment), enhanced volatilization of the volatile organic compound (VOC)-contaminated soils, and off-site disposal of the contaminated dust and fixated soils. Long-term monitoring was selected for the VOC-contaminated ground water underlying the site. (A search for VOC-contaminated soils on the plant grounds during the design failed to find a source area. Therefore, the enhanced volatilization component of the selected remedy was not designed. The subsequent demolition of the building revealed elevated levels of VOCs in some sections of the sealed process trenches and an ejector pit. The contents of the process trench and ejector pit were sent to an off-site facility for treatment/disposal.)

An RI/FS for the East Foundry Cove, West Foundry Cove, and Hudson River in the vicinity of the Cold Spring pier portion of the site (Area III) was completed in June 1989. The Area III ROD was signed on September 26, 1989. The selected remedy called for dredging one foot of contaminated sediments to achieve a 95% removal rate from East Foundry Cove and the Hudson River in the vicinity of the Village of the Cold Spring pier, followed by chemical fixation and off-site disposal. Long-term monitoring was selected for West Foundry Cove, a depositional area.

A consolidated design for Areas I, II (the dredge spoils vault and the plant grounds), and III was completed in May 1992.

Following the completion of field investigations to more fully delineate the areas of the adjacent residential properties that required remediation, in May 1992, this portion of the Area II remediation effort commenced. When the remedial action was completed in March 1993, approximately 1,600 cubic yards of contaminated soil had been excavated and removed.

On March 26, 1989, EPA issued a Unilateral Administrative Order (UAO) to Marathon Battery Company, Gould Inc., and Merchandise Dynamics, the property owner, requiring them to decontaminate the interior of the 114,000-square foot former battery plant (which at the time was an abandoned book repository) and its contents, to recycle the decontaminated books, and to properly dispose of contaminated materials. Following the performance of a pilot-scale study conducted by Marathon Battery Company's and Gould Inc.'s contractor to evaluate decontamination techniques, the facility, as well as 4,170 pallets containing approximately 2.5 million books were decontaminated. Twelve of seventy-six rolloffs containing debris from the building were determined to contain hazardous debris and were disposed of at Chemical Waste Management's hazardous landfill in Model City, New York. The remaining rolloffs were sent to Waste Management's Modern Landfill in York, Pennsylvania. While the book and building decontamination work was completed in December 1991, due to the limited production rate of available book recycling companies, the recycling of the books continued until March 1993.

A Consent Decree, in which Gould Inc. agreed to perform the remedial action and the remaining PRPs, Marathon Battery Company and the U.S. Army, agreed to a cash settlement, was entered with the Southern District Court on April 1, 1993. Gould Inc., as the Settling Work Defendant, chose Sevenson Environmental Services as its contractor. The U.S. Army Corps of Engineers (USACE) performed oversight of the work effort.

Full-scale dredging of East Foundry Cove Marsh and East Foundry Cove and the excavation of the plant grounds began in September 1993. The treated sediments and soils were stockpiled on the treatment area for curing and post-treatment testing prior to off-site disposal at City Management Landfill in Michigan. All treated materials were subjected to the Toxicity Characteristics Leaching Procedure as required by EPA and the Extraction Procedure Toxicity Test as required by the State of Michigan.

Dredging in the Hudson River in the vicinity of the Cold Spring pier was completed in early July 1994 and dredging of East Foundry Cove continued until February 1994. All dredged areas underwent post-remedial sampling and were surveyed to determine whether the proper concentration or dredging depth was achieved. With regard to East Foundry Cove Marsh, post-excavation cadmium levels in the sediments did not exceed the 100 mg/kg action level, averaging 11.75 mg/kg.

In the Hudson River and East Foundry Cove, an average of 10 mg/kg of cadmium remained, which was consistent with the ROD requirement that at least one foot of sediment and 95% of the contamination be removed.

The collection of ice and snow on the former battery facility's roof during the winter of 1993–1994 resulted in the collapse of a 10,000 square foot section of the roof, thereby exposing a portion of the concrete foundation to the outside elements. This particular portion of the foundation contained numerous trenches which were used for waste disposal during the manufacture of nickel-cadmium batteries. Sample analyses revealed that elevated levels of cadmium and nickel remained encased in the rubble-filled and cemented-over trenches. Due to EPA's concern that continued exposure to the elements and freeze/thaw cycles could cause the concrete floor and/or trenches' cement caps to heave and crack, possibly resulting in a release of contaminated dust, the PRPs agreed to demolish the building and remove the foundation and process trenches. Demolition of the former battery facility began in

September 1994 and was completed in January 1995.

Following the demolition of the former battery facility, it was discovered that a cadmium nitrate tank located on a pedestal immediately adjacent to the plant had leaked onto the underlying soil prior to the closing of the plant in 1979. In an attempt to remove this cadmium-contaminated soil, a twenty-by sixty-foot area was excavated to a depth of approximately twenty feet (approximately two feet above the ground-water table). While post-excavation sampling of this area showed that some cadmium contamination remained in the saturated soils at levels above the 20 mg/kg action level, and low levels of cadmium were present in the ground water, it was determined that excavating an additional four feet of contaminated soil (two feet below the water table), placing two feet of limestone at the bottom of the excavation (to keep the cadmium insoluble), and backfilling the excavation with clean fill would be protective of public health and the environment.

At the completion of the marsh remediation and restoration activities in April 1995, the marsh was planted with cattails, bull rush, arrow arrum, and upland shrubs in specified areas.

The plant grounds were regraded and reseeded in July 1995. Fourteen monitoring wells remain in place on the plant grounds for the long-term monitoring of the ground water for VOCs and cadmium.

In all, 189,265 tons of treated soils and sediments were transported off-site (via 1,979 railcars) to City Management Landfill in Michigan. Chemical Waste Management's hazardous waste landfill in Model City, New York received 906 tons of hazardous materials.

A Remedial Action Report associated with the remediation of the adjacent properties was approved on September 28, 1993. A Remedial Action Report associated with the East Foundry Cove, East Foundry Cove Marsh, Hudson River in the vicinity of the Cold Spring pier, the former battery facility, and plant grounds portions of the site was approved on September 18, 1995. A Superfund Site Close-Out Report was approved on September 28, 1995.

Summary of Operation and Maintenance and Five-Year Review Requirements

The cattails, bull rush, and arrow arrum, as well as the upland shrubs, are being monitored on a regular basis by the warden of the adjacent National Audubon sanctuary, Constitution Marsh.

The Settling Defendants have agreed to monitor the site for up to thirty years, commencing with the first inspection/monitoring event that occurred on October 27, 1995.

The long-term monitoring program consists of monitoring the groundwater, East and West Foundry Cove sediments and surface water and biological sampling and analysis quarterly the first year, semi-annually during years two through five, and annually thereafter for a total of thirty years.

Site inspections are to be coincident with the monitoring events. The inspections will include visual observations of the marsh soil cover and erosion controls, groundwater monitoring wells, and general site conditions. Maintenance, if required, will consist of correcting observed deficiencies (e.g., repairing ground water monitoring wells) The fourteen groundwater monitoring wells that comprise the groundwater monitoring program will be inspected to ensure their integrity. They will be repaired should they become damaged, or replaced should they become non-functional.

So that EPA can evaluate the remedy's effectiveness, following each inspection/sampling event, Gould Inc. is to submit to EPA a monitoring and inspection program report, summarizing the inspection and sampling results, and describing any corrective maintenance actions that were taken. In addition, a review of the long-term monitoring and inspection program reports will be performed five years after the completion of the RA to assure that the remedy remains effective in protecting human health and the environment.

There are no operational requirements related to the implemented remedy.

Summary of How the Deletion Criteria Has Been Met

Based upon the results of RA sample analyses, survey results, and site inspections, the site meets the requirements set forth in the RODs. All contaminated soils and sediments above the specific action levels set for each operable unit were excavated and/or dredged from those areas, treated and disposed of off-site. East Foundry Cove Marsh and the plant grounds have been regraded with clean fill and restored. An Explanation of Significant Differences, dated May 1995, was issued by EPA to address the pedestal area on the plant grounds which exceeds the action level at a depth of 20 feet. However, EPA believes the placement of two feet of limestone at the bottom of the excavation to keep the cadmium insoluble, and the backfilling of the excavation with clean fill is protective of public health and the environment.

EPA and the State have determined that the response actions undertaken at the Marathon Battery Company site are protective of human health and the environment.

In accordance with 40 CFR § 300.425 (e), sites may be deleted from the NPL where no further response is appropriate. EPA, in consultation with the State, has determined that all appropriate responses under CERCLA have been implemented and that no further cleanup by responsible parties is appropriate. Having met the deletion criteria, EPA proposes to delete the Marathon Battery Company site from the NPL.

The State has advised EPA that, upon deletion of the Marathon Battery Company site from the NPL, it proposes to change the classification of the site on its Registry of Inactive Hazardous Waste Sites from a Class 2 (a site where the disposal of a consequential quantity of hazardous waste has been confirmed and presents a significant threat to the environment or health) to a Class 4 (a site that has been properly closed, but requires continued operation, maintenance, and/or monitoring).

Dated: April 12, 1996.

William J. Muszynski,

Acting Regional Administrator.

[FR Doc. 96–11481 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 96–103; RM–8794]

Radio Broadcasting Services; Smith, NV

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: The Commission requests comments on a petition filed by Donegal Enterprises, Inc., seeking the allotment of Channel 271C3 to Smith, Nevada, as the community's first local aural service. Channel 271C3 can be allotted to Smith in compliance with the Commission's minimum distance separation requirements with a site restriction of 3.9 kilometers (2.4 miles) east, at coordinates 38–47–53 NL; 119–16–55 WL, to avoid a short-spacing to Station KSSJ, Channel 270B, Shingle Springs, CA.

DATES: Comments must be filed on or before June 27, 1996, and reply comments on or before July 12, 1996.

ADDRESSES: Federal Communications Commission, Washington, DC 20554. In addition to filing comments with the FCC, interested parties should serve the petitioner, or its counsel or consultant, as follows: Patrick A. Mulreany, President, Donegal Enterprises, Inc., P.O. Box 123, Smith, Nevada 89430 (Petitioner).

FOR FURTHER INFORMATION CONTACT: Leslie K. Shapiro, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's *Notice of Proposed Rule Making,* MM Docket No. 96–103, adopted April 22, 1996, and released May 6, 1996. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, International Transcription Services, Inc., (202) 857–3800, 2100 M Street, NW., Suite 140, Washington, DC 20037.

Provisions of the Regulatory Flexibility Act of 1980 do not apply to this proceeding.

Members of the public should note that from the time a Notice of Proposed Rule Making is issued until the matter is no longer subject to Commission consideration or court review, all *ex parte* contacts are prohibited in Commission proceedings, such as this one, which involve channel allotments. See 47 CFR 1.1204(b) for rules governing permissible *ex parte* contacts.

For information regarding proper filing procedures for comments, see 47 CFR 1.415 and 1.420.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Federal Communications Commission.

Andrew J. Rhodes,

Acting Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 96–11760 Filed 5–9–96; 8:45 am]

BILLING CODE 6712–01–F

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

RIN 1018–AD20

Endangered and Threatened Wildlife and Plants; Proposed Special Rule for the Conservation of the Northern Spotted Owl on Non-Federal Lands

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Proposed special rule; additional information.

SUMMARY: On February 23, 1996, the Service issued a Draft Environmental Alternatives Analysis (EAA) for the proposed special section 4(d)rule for the conservation of the northern spotted owl on non-Federal lands in California and Washington. The proposed special rule was published in the Federal Register on February 17, 1995 (60 FR 9484). The comment period for the draft EAA and the proposed rule was recently extended, (61 FR 15452, April 8, 1996) and is scheduled to end for both documents on June 3, 1996.

The comment period was extended, in part, to allow the public the opportunity to review a proposal by the State of Washington Forest Practices Board that would address impacts of forest practices to the northern spotted owl. The state has asked the Service to consider their proposed state rule as a possible alternative to the current special rule proposed by the Service. The Service seeks additional comments from the interested public, agencies, and interest groups on the Draft EAA, the proposed special rule, and on the State of Washington's proposed state rule as a possible alternative to the rule currently proposed by the Fish and Wildlife. The purpose of this document is to provide a summary of Washington's proposed rule, and a comparison of that rule with the Service's proposed special rule.

DATES: The comment period for written comments closes June 3, 1996.

ADDRESSES: Comments and materials concerning the Draft Environmental Alternatives Analysis, the proposed rule and the potential use of the Washington Forest Practices Board proposed rule as an additional alternative should be sent to Mr. Michael J. Spear, Regional Director, Region 1, U.S. Fish and Wildlife Service, 911 N.E. 11th Avenue, Portland, Oregon 97232–4181. The complete file for this proposed rule will be available for public inspection, by appointment during normal business hours, at the U.S. Fish and Wildlife Service, Office of Technical Support for Forest Resources, 333 S.W. 1st Avenue, 4th Floor, Portland, Oregon 97204, (503/326–6218).

FOR FURTHER INFORMATION CONTACT: Mr. Curt Smitch, Assistant Regional Director, Region 1, U.S. Fish and Wildlife Service, 3704 Griffin Lane S.E., Suite 102, Olympia, Washington 98501, (206/534–9330); or Ron Crete, Office of Technical Support for Forest Resources, 333 S.W. 1st Avenue, Portland, Oregon 97232–4181, (503/326–6218).

SUPPLEMENTARY INFORMATION: The Service published its proposed rule under section 4(d) of the Endangered Species Act on February 17, 1995 (60 FR 9484), followed by the release of the draft Environmental Alternatives Analysis (EAA) which describes and analyzes the potential environmental effects of the proposed special rule and six alternatives for the conservation of the northern spotted owl on non-Federal lands in Washington and California.

The State of Washington's Forest Practices Board (Board) began work in 1993 to develop a rule to address the impacts of forest practices on northern spotted owls in that state. Following the publication of the Service's proposed rule, the Board accelerated work on the current version of the proposed state rule. The northern spotted owl is listed as endangered by the Washington Fish and Wildlife Commission. The state's proposed rule is similar in many ways to the Service's proposed 4(d) rule, although there are some differences. The state has asked the Service to consider the state's proposed rule as an alternative to the Service's current proposed rule.

The rule proposed by the Washington Forest Practices Board would classify forest practices in spotted owl habitat as ''Class IV-Special''. Class IV-Special designation includes forest practices within critical wildlife habitats (state) of species listed as threatened or endangered under either the Federal Endangered Species Act or state law, and requires that certain forest practices proposed to occur in these habitat areas be evaluated relative to their potential to have substantial impacts to the environment. Such forest practices may include timber harvesting, road construction and aerial spraying of pesticides, and are subject to environmental review under the State Environmental Policy Act (SEPA).

A review under SEPA involves a detailed analysis of a proposed action to determine if it will have a significant impact on the environment. Should a finding of significance be made, then an Environmental Impact Statement (EIS)

must be prepared before the Department of Natural Resources (DNR) can act on a forest practice application. Under SEPA, the forest practice may be conditioned or denied, if necessary, to mitigate specific adverse environmental impacts.

The Board's goal in developing its proposed rule was to ''prepare a rule that captures all forest practices that have potential for a substantial adverse impact on the environment. In the case of the owl, any forest practice that damages the long-term viability of the northern spotted owl in Washington State (WDNR 1996).'' The Board also adopted five objectives to support the proposed rule (WDNR 1996):

(1) Define a level of [owl conservation] contribution from nonfederal lands that is essential to complement the federal recovery and conservation strategy for the northern spotted owl population in Washington State.

(2) Identify those landscapes that are essential to complement the federal conservation and recovery strategy. Identify whether their primary function is for dispersal or population maintenance.

(3) Maximize the use of local planning to promote flexibility. To do this, provide as specific criteria as possible for different levels of planning.

(4) Minimize conflicts between federal and state standards.

(5) Minimize economic impacts.

Generally, the Board's proposed rule involves ten spotted owl special emphasis areas (SOSEAs) that are made up of all or parts of 13 landscapes identified in the Spotted Owl Scientific Advisory Group (SAG) Report (Hanson et al. 1993). The proposed state rule assigns specific owl conservation functions or goals to the SOSEAs, includes a small parcel exemption, disturbance restrictions, and provides provisions for optional landowner conservation planning. Within the SOSEAs, areas are designated for either dispersal or demographic support, or a combination of both. Figure 1 shows the location of the SOSEAs.

Within all the SOSEAs, except the one for the Entiat area, the proposed state rule would designate harvesting, road construction or aerial application of pesticides on suitable spotted owl habitat inside owl nesting circles (site centers) with less than specified amounts of suitable habitat as Class IV-Special activities, triggering a review under SEPA. Within the Entiat SOSEA, the SEPA trigger would only apply on suitable habitat inside owl circles and inside the areas designated for demographic support. The specified amounts of suitable habitat include 5,863 acres within a 2.7 mile circle for the Hoh- Clearwater/Coastal Link SOSEA, and 2,605 acres within a 1.8 mile circle for all other SOSEAs.

Both inside and outside SOSEAs, harvesting, road construction or aerial application of pesticides between March 1 and August 31, on the 70 acres of highest quality suitable owl habitat surrounding the site center, would be Class IV-Special actions.

The proposed state rule provides several exemptions to the SEPA trigger within the SOSEAs: an approved landowner option plan (LOP); an approved habitat conservation plan (HCP) from the Fish and Wildlife Service; pre-listing agreements or habitat management plan accompanied by a ''no-take'' letter from the Fish and Wildlife Service; and the provisions of a final 4(d) rule adopted by the Fish and Wildlife Service. A small parcel exemption is provided if a landowner owns 500 acres or less within the SOSEA and the proposed forest practice is not within 0.7 mile of a northern spotted owl site center.

The planning components of the proposed state rule include the LOP and the cooperative habitat enhancement agreement (CHEA). The details of the LOP process have not been finalized, and may be added to the rule at a later date. The CHEA option is available to landowners not currently impacted by owls, and is intended to preclude early harvesting based on fear of regulatory impact and to provide additional owl habitat. Under the provisions of Washington's proposed rule, if habitat is allowed to be harvested within an owl circle through one of the planning options (LOP, CHEA or HCP), the harvested habitat will continue to be counted in the calculation of suitable habitat from the date of plan approval and forward, even after harvest has occurred. The state's intent with this provision is to prevent the transfer of responsibility for maintenance of habitat from one landowner within an owl circle to another.

This state proposal also includes disturbance restrictions inside SOSEAs during nesting season that apply within .25 mile of a site center between March 1 and August 31, unless affected owls are not actively nesting.

It is important to note that the Service's proposed special 4(d) rule is based on avoidance of incidental take prohibitions for the owl. The State's proposed rule is based on the avoidance of triggering the requirements of a review under Washington's SEPA rather than on avoidance of incidental take prohibitions.

A tabular comparison of the Washington proposed rule and the Service's proposed 4(d) rule is provided in Table 1.

TABLE 1

Rule provision	Washington proposed rule	Service proposed rule
1. Landscapes	10 SOSEAs: Columbia Gorge*	6 SEAs: Columbia River Gorge/White Salmon.
	Entiat * (Special SEPA trigger)	(Not proposed).
	Finney Block	Finney Block.
	I–90 West	I–90 Corridor (includes I–90E, I–90W, Taneum, Easton, Blewett).
	I–90 East* (includes Teanaway, Taneum, Easton)	
	Mineral Block/Link	Mineral Block (includes Mineral Link).
	Siouxon*	Siouxon Creek (included in other SEA) (included in other SEA).
	White Salmon *	
	North Blewett	
	Hoh-Clearwater/Coastal Link	Hoh-Clearwater.
	* Means modified from original SAG boundaries	SEAs may provide dispersal, demographic or combination support, to be decided on a case by case basis, except in areas surrounded by or located in matrix or AMA lands, except if sites are centered on reserve or withdrawn areas.
	Note: SOSEA goals/functions are identified on Figure 1	
2. Owl Circle Dimensions:		

TABLE 1—Continued

Rule provision	Washington proposed rule	Service proposed rule
Inside SOSEAs	All SOSEAs: All habitats within 0.7 miles/1,000 acres retained. Hoh-Clearwater SOSEA: 5,863 acres of suitable owl habitat within median owl home range circle (2.7 mile radius) must be retained. All other SOSEAs: 2,605 acres of suitable owl habitat within median owl home range circle (1.8 mile radius) must be retained	Dimensions are discussed in the preamble to the proposed 4(d) rule and the DEAA. Median annual home range, approximately the same size as state proposal. At least 40 percent suitable owl habitat within owl median home range must be retained.
Outside SOSEAs	The 70 acres highest quality habitat around the site center must be retained from March 1 through Aug. 31.	The 70 acres of highest quality habitat closest to an owl site center must be retained.
3. SEPA Trigger:		
Within Important Landscapes.	Within SOSEA boundaries harvesting, road construction or aerial application of pesticides on suitable habitat inside owl circles (except within the Entiat SOSEA where the trigger applies only on suitable habitat inside owl circles and inside the areas indicated for demographic support.).	Federal permit requirement, no NEPA trigger exists.
Outside Important Landscapes.	Outside of a SOSEA: harvesting, road construction, or aerial application of pesticides between March 1 and August 31, on the 70 acres of highest quality suitable habitat	
Exemptions to SEPA	—Under an approved Landowner Option Plan —HCP approved by USFWS —Prelisting agreements or habitat management plan accompanied by a ''no-take'' letter from the USFWS —4(d) rule adopted by the USFWS —Small parcel exemption	
4. Prohibited Activities:		
Within Important Landscapes.	The SEPA triggers in the state proposal require SEPA review, they do not prohibit activities.	Under the ESA, ''incidental take'' is generally prohibited and is only allowed under limited circumstances. Timber harvest activities are prohibited in SEAs if they result in the incidental take of a spotted owl (a significant likelihood if suitable habitat drops below 40 percent within the median annual owl home range.) Alternative proscription allows harvesting on non-Federal lands surrounded by or located in Federal matrix or AMA lands if the Federal matrix or AMA prescriptions and restrictions are followed.
Outside Important Landscapes.	(No equivalent)	Timber harvest actions are prohibited if they result in retention of less than 70 acres of highest quality suitable habitat closest to the site center or impact the sites centered inside Federal Reserves, Administratively withdrawn lands or Congressionally reserved lands (no seasonal restrictions). Incidental take of owls is not authorized for owls whose site center is located within or along the boundary of a Federal reserve or Administratively withdrawn lands or Congressionally reserved lands (except on the Olympic Peninsula), or along or within the boundary of an SEA.
Exemptions to Prohibitions.	(No equivalent)	Harvest is allowed: —With an approved HCP; —With an approved Local Option Plan; —With a Spotted Owl Habitat Enhancement Agreement.
5. Planning Components Needed to Authorize Incidental Take:.	Establishes a process for the development of the Landowner Option Plan (LOP):. —Description of area; —Identifies elements that are to be included in a LOP: —Goals and objectives —Planning area description —Physical features —Current spotted owl habitat status —Current owl status —Management proposals and operation plans —Projected spotted owl habitats —Training —Monitoring —Reporting	Habitat Conservation Plan (HCP) required for owners of more than 5,000 acres. HCPs must include:

TABLE 1—Continued

Rule provision	Washington proposed rule	Service proposed rule
	—Plan modification —Plan duration —Approval process —Enforcement process	
	(No equivalent)	Proposes a Local Option Conservation Plan (Short-Form HCP) for Owners of 80–5,000 acres. Basic criteria generally same as for regular HCP although the application process will be streamlined.
	Establishes a process for the development of Cooperative Habitat Enhancement Agreements. Identified elements: —Description of agreement area —Current owl habitat status —Management proposals —Projected habitat development —Agreement modification —Agreement duration —Approval process —Enforcement process Agreement to be approved by DNR in consultation with Washington Department of Fish and Wildlife, others..	Proposes similar Habitat Enhancement Agreement process.
6. Disturbance	Road construction within SOSEA boundary restricted within .25 miles of site center between March 1 and August 31, unless owls are not actively nesting. Felling and bucking within SOSEA boundary restricted within .25 miles of site center between March 1 and August 31, unless owls are not actively nesting. Cable yarding within a SOSEA boundary restricted within .25 miles of site center between March 1 and August 31, unless owls are not actively nesting.. Helicopter yarding within SOSEA boundary restricted within .25 miles of site center between March 1 and August 31, unless the owls are not actively nesting.. Tractor and wheel skidding systems operations of heavy equipment within a SOSEA boundary restricted within .25 miles of site center between March 1 and August 31, unless the owls are not actively nesting.. Slash disposal or prescribed burning within a SOSEA boundary restricted within .25 miles of site center between March 1 and August 31, unless the owls are not actively nesting..	(No equivalent proposal).
7. Small Landowner Exemption.	Provides for small parcel exemption: ..... —If a landowner owns or controls 500 acres or less within the SOSEA; and —The forest practice is not within .7 mile of a site center	Owners of not more than 80 acres of forest land not restricted as long as harvest does not destroy or degrade the 70 acres of suitable habitat closest to the owl site center.

The Service is in the process of analyzing the state's proposed rule as a possible alternative to the Service's proposed 4(d) rule published February 17, 1995. The state's comment period for their proposed rule has expired, however, the Service is interested in receiving comment from the interested public regarding the advisability of adapting some or all of the Washington state rule in any final 4(d) rule that the Service may publish. To receive an actual copy of the State of Washington proposed rule and the state's Supplemental Draft Environmental Impact Statement, write to Washington State Department of Natural Resources, Forest Practices Division, P.O. Box 47012, Olympia, WA 98504–7012, Attn: Judith Holter.

The Service's Draft EAA, including all maps, tables, charts, and graphs, remains available on the Internet's World Wide Web at http://www.r1.fws.gov/4deaa/welcome.html.

References Cited

Hanson, E., Hays, D., Hicks, L., Young, L., and J. Buchanan. 1993. Spotted owl habitat in Washington: a report to the Washington Forest Practices Board. Washington Forest Practices Board Spotted Owl Advisory Group. Olympia, Washington.

WDNR. 1996. Supplemental draft environmental impact statement and appendices on forest practices rule proposals for the northern spotted owl. Washington Forest Practices Board, Washington Department of Natural Resources. Olympia, Washington.

Dated: April 30, 1996.

Thomas Dwyer,

Acting Regional Director, U.S. Fish and Wildlife Service Region 1, Portland, Oregon.

BILLING CODE 4310–55–P

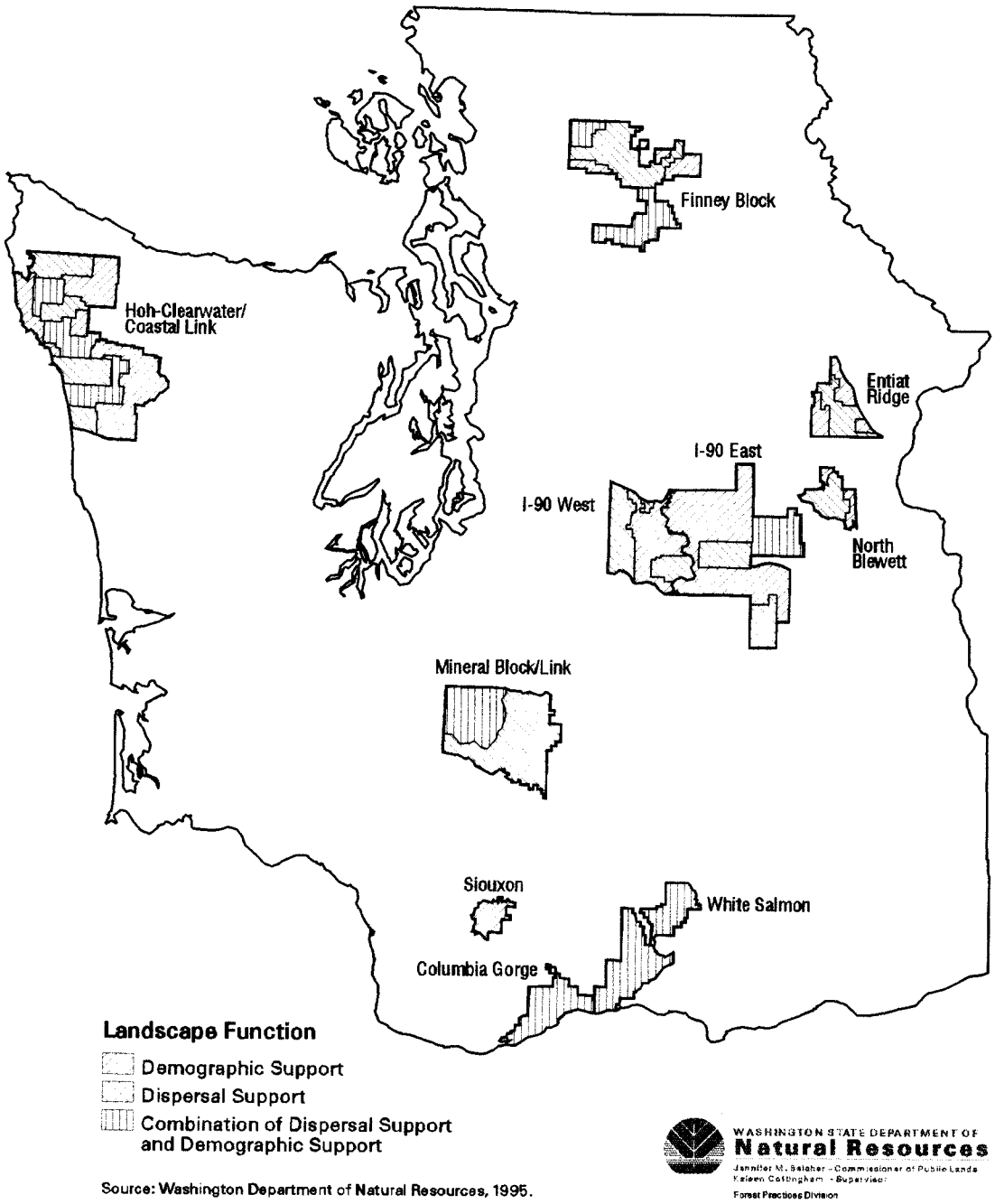

Figure 1. Spotted Owl Special Emphasis Areas (SOSEAS).

[FR Doc. 96–11213 Filed 5–9–96; 8:45 am]
BILLING CODE 4310–55–C

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 650

[I.D. 042996G]

New England Fishery Management Council; Public Hearing

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Public hearing; request for comments.

SUMMARY: The New England Fishery Management Council (Council) will hold a public hearing to seek input on Amendment 5 to the Atlantic Sea Scallop Fishery Management Plan (FMP). Amendment 5 would close an area to some fishing activities over an 18-month period to allow an experiment and demonstration project involving sea scallop research, resource enhancement, and aquaculture.

DATES: Written comments must be received on or before June 4, 1996. The hearing will be held on Friday, May 17, 1996, at 1 p.m.

ADDRESSES: Requests for special accommodations should be addressed to the New England Fishery Management Council, 5 Broadway, Saugus, MA 01906–1097. Copies of proposed Amendment 5 will be available at the hearing, but may be obtained in advance by calling or writing the Council office.

The hearing will take place at the University of Massachusetts Cranberry Experiment Station, Glen Charlie Road, Wareham, MA; telephone: (508) 295–2212.

FOR FURTHER INFORMATION CONTACT: Douglas G. Marshall, Executive Director, New England Fishery Management Council, (671) 231–0422.

SUPPLEMENTARY INFORMATION: Fishermen and any other interested members of the public are encouraged to attend this hearing to review a proposal to amend the FMP. Amendment 5 would establish a temporary experimental use area in Federal waters approximately 12 miles (22.22 km) southwest of Martha's Vineyard. During the 18-month-long project, the area would be used to determine whether it is feasible to enhance wild stocks through bottom seeding, and to study the interactions of the harvesting gear, sea scallops and their habitat, open-ocean pen engineering, and the growth rates of transferred juvenile brood stock in both pen culture and open bottom culture.

Otter trawling, mid-water trawling and the use of other mobile gear, shellfish dredging and gillnetting would be prohibited within the 9 square-mile (23.31 square-km) site. Other fishing gear such as lobster traps and longline gear would be controlled but allowed within the area and the operation of hand gear would not be restricted. If the project is approved, the Council will amend the FMP accordingly.

Discussion of this issue will be included on the agenda at the Council's June 5–6, 1996, meeting at the King's Grant Inn, Danvers, MA. There will be an opportunity for public comment at that time.

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Douglas G. Marshall (see **ADDRESSES**) at least 5 days prior to the meeting date.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: May 6, 1996.

Richard W. Surdi,

Acting Director, Office of Fisheries Conservation and Management, National Marine Fisheries Service.

[FR Doc. 96–11772 Filed 5–9–96; 8:45 am]

BILLING CODE 3510–22–F

50 CFR Part 673

[Docket No. 960502124–6124–01; I.D. 042396B]

RIN 0648–AF81

Scallop Fishery off Alaska; Federal Management Regime

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Proposed rule; proposed 1996 scallop harvest specifications; request for comments.

SUMMARY: NMFS proposes regulations to implement Amendment 1 to the Fishery Management Plan for the Scallop Fishery off Alaska (FMP). Amendment 1 would establish a Federal management regime for the scallop fishery in Federal waters off Alaska. The management measures proposed under Amendment 1 include: Gear and efficiency restrictions, scallop registration areas and districts, procedures for specifying total allowable catch (TAC) and crab bycatch limits (CBLs), time and area closures, inseason management authority, fishing seasons, and observer coverage requirements. This action is necessary to further the conservation and management objectives of the FMP and the Magnuson Fishery Conservation and Management Act (Magnuson Act).

DATES: Comments must be received by June 21, 1996.

ADDRESSES: Comments must be sent to Ronald J. Berg, Chief, Fisheries Management Division, Alaska Region, NMFS, P.O. Box 21668, Juneau, AK 99802, Attn: Lori J. Gravel. Copies of the proposed FMP amendment and the Environmental Assessment/ Regulatory Impact Review/Initial Regulatory Flexibility Analysis (EA/RIR/IRFA) prepared for this action may be obtained from the same address.

FOR FURTHER INFORMATION CONTACT: Kent Lind, 907–586–7228.

SUPPLEMENTARY INFORMATION:

Background

The scallop fishery in the exclusive economic zone (Federal waters) off Alaska is managed under the FMP. The FMP was prepared by the North Pacific Fishery Management Council (Council) under the Magnuson Act. The FMP was approved by NMFS on July 26, 1995. The only management measure currently authorized under the FMP is an interim closure of Federal waters off Alaska to fishing for scallops for 1 year, or until an amendment to the FMP is prepared that would provide for a managed fishery in Federal waters. The interim closure will expire on August 28, 1996. Regulations implementing the FMP are set out at 50 CFR part 673. General regulations that also affect fishing in Federal waters are set out at 50 CFR part 620. The history of the scallop fishery off Alaska, as well as the events leading up to the interim closure of Federal waters are described in the FMP and in the preambles to the proposed and final rules implementing the FMP (60 FR 24822, May 10, 1995, and 60 FR 42070, August 15, 1995, respectively).

In June 1995, the Council adopted Amendment 1 to the FMP, which would authorize Federal management measures to replace the interim closure of Federal waters to fishing for scallops. The Council's preferred alternative for Amendment 1 was to incorporate certain State of Alaska (State) management measures into the Federal regulations and implement a vessel moratorium based on criteria adopted in April 1994 and reaffirmed in January 1995. Eighteen vessels would qualify under the moratorium. The Council subsequently separated the moratorium from Amendment 1 and will propose a vessel moratorium as Amendment 2. Such action was taken to prevent moratorium issues from delaying the reopening of the fishery.

At its January 1993 meeting, the Council determined that unrestricted access to the scallop fishery may be harmful to the resource and result in a net loss to the Nation. The Council announced a control date of January 20, 1993, to place the industry on notice that a moratorium for this fishery may be implemented and any person or fishing vessel that entered the scallop fisheries in Federal waters off Alaska would not be assured of future access to those fishery resources if a moratorium is implemented. This control date was again reaffirmed at the Council's June 1993 and June 1995 meetings. The January 20, 1993, control date, which was published in the Council's newsletter, means that fishermen and/or vessels not participating in the fishery by that date may not be guaranteed future access to the fishery. NMFS notifies current and future participants in the scallop fisheries that landings made after January 20, 1993, may not count toward allocations of catch under future Federal management and may not be guaranteed future access to the scallop fishery.

The regulations proposed under Amendment 1 were developed in coordination with the Council and the State, and are designed to complement current State management of the scallop fishery. These proposed regulations would not preclude the State from imposing additional regulations on State registered vessels fishing in Federal waters, so long as State regulations are consistent with the FMP and its implementing regulations. The following explains each aspect of the proposed rule.

Gear and Efficiency Restrictions

The primary purpose for restrictions on fishing gear and processing efficiency is to prevent overfishing of undersize scallops. Restrictions on the ring size of scallop dredges are designed to prevent the harvest of juvenile scallops. Limits on dredge widths, crew size, and automatic shucking machines are designed to discourage vessels from targeting on juvenile scallops. The amount of scallops that can be processed on board vessels depends on how fast the scallops can be sorted and shucked. Because larger scallops are worth more per meat, and take the same amount of processing time as small scallops, a limited crew size and a ban on automatic shucking machines would provide an economic incentive for vessels to target larger sized, higher yield, mature scallops. Efficiency limits would also tend to allocate the resource evenly among vessels, regardless of an individual vessel's potential harvesting capacity.

The following gear and efficiency restrictions are proposed:

1. The inside ring diameter on all dredges used or carried by a vessel fishing for weathervane scallops (*Patinopectin caurinus*) must be 4 inches (10.16 cm) or larger.

2. The inside ring diameter on all dredges used or carried by a vessel fishing for scallops other than weathervane scallops must be 3 inches (7.62 cm) or larger.

3. No person may use chafing gear or other devices that decrease the legal inside ring diameter of a scallop dredge.

4. Except as provided in item 5 below, no more than two scallop dredges may be operated at one time from a vessel, and the opening of a scallop dredge must be equal to or less than 15 ft (4.57 m) wide.

5. In the Kamishak, Southern, and Central Districts of Scallop Registration Area H, no more than one scallop dredge may be operated at one time from a vessel, and the opening of a dredge may not be more than 6 ft (1.83 m) in width.

6. Scallops must be shucked by hand only. A shucking machine must not be on board a vessel that is fishing for scallops or that has scallops on board.

7. No vessel fishing for scallops in Federal waters may have aboard more than 12 persons, exclusive of the Alaska Department of Fish and Game (ADF&G) or NMFS observers.

Registration Areas

The management area covered under the FMP comprises the Federal waters off Alaska south of the Bering Strait. The cooperative State-Federal management approach outlined in the FMP requires that ADF&G and NMFS use the same registration areas to manage the scallop fishery. This proposed rule would establish nine scallop registration areas composed of the Federal waters and adjacent State waters described in each area. The nine scallop registration areas correspond to the Southeastern, Yakutat, Prince William Sound, Cook Inlet, Kodiak, Alaska Peninsula, Dutch Harbor, Adak, and Bering Sea portions of the State. These scallop registration areas are identical to the nine State scallop registration areas described in State regulations at 5 AAC 38.076(b). The Yakutat, Cook Inlet, and Kodiak scallop registration areas would be subdivided into districts to allow for more precise management of scallop resources in these areas.

Optimum Yield and Overfishing

The FMP establishes the Optimum Yield (OY) for the scallop fishery as a numeric range based on the long-term productivity of the scallop resource and is derived from historical catches since 1978. At present, the FMP establishes an OY for the scallop fishery in Federal waters as a range from zero to 1.1 million lb (0–499.0 mt) of shucked scallop meat. Because NMFS and the State have agreed to manage the scallop fishery within each registration area as a unit throughout Federal and State waters, Amendment 1 also would raise the upper end of the OY range to 1.8 million lb (816.5 mt) to reflect historical catches in State waters.

Under the FMP, overfishing for scallops is defined as landings that exceed OY. Overfishing could be defined as a fishing mortality rate for scallops, based on existing life history data, but the lack of stock assessment information (surveys, population age or size structure) limits the use of a mortality rate-based overfishing definition at this time. Therefore, Amendment 1 does not propose to change the definition of ''overfishing'' contained in the FMP. As data collected from the fishery and/or assessment surveys of the scallop resource are analyzed, the definition of ''overfishing'' for scallops could be changed to a fishing mortality rate basis.

Harvest Limits

The management measures proposed by this rule would allow NMFS to specify annual scallop TACs and CBLs. In registration areas where the scallop fishery has occurred traditionally, and where ADF&G has established Guideline Harvest Levels (GHLs), NMFS would establish annual TACs equal to a specified total weight of shucked scallop meat. These areas include all or parts of Scallop Registration Areas A (Southeastern), D (Yakutat), E (Prince William Sound), H (Cook Inlet), K (Kodiak), and O (Dutch Harbor). In areas where bycatch of crab is a concern, NMFS would specify annual CBLs for red king crab and Tanner crab species. These areas include all or parts of Scallop Registration Areas K (Kodiak), M (Alaska Peninsula), O (Dutch Harbor), Q (Bering Sea), and R (Adak). In areas where an adequate historic scallop catch record does not exist (areas M, Q, and R), TACs would not be specified numerically. Instead, annual TACs in those areas would simply be equal to the total weight of shucked scallop meat that could be harvested under the specified CBLs, the sum of which cannot exceed a level equal to the upper

end of the OY range minus the sum of the TACs in Registration Areas A, D, E, H, K, and O. The total amount of scallops harvested under these CBLs is expected to be within conservation limits and the total scallop harvest off Alaska cannot exceed the upper end of the OY range of 1.8 million lb (816.5 mt). The CBLs are expected to limit total catch to a fraction of what would be available under a TAC specified for scallops while continuing to allow the fishing fleet adequate opportunity to explore and harvest scallop stocks while protecting the crab resource.

Annual TACs and CBLs may be adjusted based on a review of the biological condition of each scallop or crab bycatch species or socioeconomic considerations that are consistent with the goals and objectives of the FMP. Biological assessments will include, where practicable, updated estimates of maximum sustainable yield and acceptable biological catch; historical catch trends and current catch statistics; assessments of alternative harvesting strategies; and relevant information related to changes in scallop markets.

In Scallop Registration Area Q (Bering Sea), the Council recommended that the annual red king crab bycatch limit be set within a range of 500 to 3,000 crab. The Council also recommended that bycatch limits for Tanner crab be specified annually based on a percentage of the best available estimate of crab abundance, which is derived each year from NMFS survey data. The Council approved the following percentages for Tanner crab species: *Chionoecetes opilio,* 0.003176 percent and *Chionoecetes bairdi,* 0.13542 percent which would equate to about 275,000 opilio and 257,000 bairdi crab based on the 1995 NMFS crab survey data.

Procedure for Specifying TACs and CBLs

Amendment 1 proposes an annual process whereby the Council would announce the State's most recent recommendations for scallop TACs and CBLs and the bases for the recommendations to the public and provide copies of the information upon request. Copies of the annual Stock Assessment and Fishery Evaluation (SAFE) report would also be made available at this time. The Council would notify the public of its intent to develop final recommendations at a subsequent Council meeting (usually April) and solicit public comment both before and during that meeting. After considering the SAFE report, public comments, and other relevant information, the Council would submit its TAC and CBL recommendations along with the rationale and supporting information to NMFS for review and implementation. As soon as practicable, after receiving recommendations from the Council and ADF&G, NMFS would publish in the Federal Register annual specifications of TAC and CBLs for the following fishing year. To accommodate the annual specification process, the scallop fishing year would be a 12-month period starting July 1 and ending June 30 of the following year.

Time and Area Closures

Specific Federal waters are proposed to be closed to fishing for scallops to prevent dredging in biologically critical habitat areas. These include locations of high bycatch of crab, nursery areas for young fish and shellfish, and walrus rookeries. Under this proposed rule, all Federal waters that are currently closed to trawling for groundfish with nonpelagic trawl gear for the purpose of habitat protection, limiting crab bycatch or protecting walrus rookeries and Stellar sea lion areas would also be closed to dredging for scallops. These areas are described at § 672.24 (d) and (e); § 675.22 (a), (b), and (f); and § 675.24(g). These Federal closures would not preclude the State from closing additional areas within State or Federal waters to scallop fishing by State-registered vessels.

Inseason Management Authority

This management measure would allow NMFS to make inseason adjustments such as the closure, extension, opening or reopening of a season in all or part of the Federal waters of a scallop registration area; and the adjustment of TACs or CBLs. Any inseason adjustment would be made in accordance with the procedures for inseason adjustments in the groundfish fisheries off Alaska set out at § 672.22.

Fishing Seasons

Under this rule, fishing seasons in Federal waters would be established that complement the fishing seasons currently established by the State for each scallop registration area. The State established fishing seasons in coordination with industry to focus the scallop fishery during time periods when the quality of scallop meats is highest and the bycatch of molting crab is lowest. Fishing for scallops in the Federal waters off Alaska would be authorized from 0001 hours, A.l.t., July 1, through 2400 hours, A.l.t., June 30 of the following year, except as follows: (1) In Scallop Registration Areas A, D, and E, the fishing season would run from 1200 hours, A.l.t., January 10 through 2400 hours, A.l.t., June 30; (2) in Scallop Registration Areas K, M, O, Q, and R, the fishing season would run from 1200 hours, A.l.t., July 1 through 1200 hours, A.l.t., February 15 of the following year; and (3) in the Kamishak District of Scallop Registration Area H, the fishing season would run from 1200 hours, A.l.t., August 15 through 1200 hours, A.l.t., October 31.

Observer Coverage Requirements

Except for vessels under 80 ft (24.4 m) length overall fishing in Registration Area H (Cook Inlet), all vessels fishing for scallops would be required to carry a NMFS or ADF&G-certified scallop observer at all times. Operators of vessels required to carry an observer would be required to meet all of the safety and conduct requirements currently in place for the groundfish fisheries off Alaska set out at § 677.10 (c) and (g).

Proposed Total Allowable Catch Specifications

Table 1 shows proposed TACs for the period [insert effective date of the final rule] through June 30, 1997. These proposed TACs reflect the most recent GHLs established by the State. In the absence of surveys, the State established the upper GHL for the Yakutat, Kodiak, and Dutch Harbor Registration Areas as the average of the historic catch from 1969 to 1994 minus years when no fishery and ''fishing-up effect'' occurs. The term ''fishing-up effect'' is used to describe the initial exploitation phase of a new fishery or removal of accumulated stock. The recent development of scallop fisheries in Prince William Sound and Cook Inlet necessitates use of methods other than averaging historic catch data for estimating TACs. The proposed TACs for the Prince William Sound and Cook Inlet Registration Areas are based on estimates of exploitable biomass, a 10 percent harvest rate and a conversion factor of 10 percent average meat weight to total animal weight. Exploitable biomass for Prince William Sound is calculated using area swept methods with information from fishermen on bed size, average towing speed, and pounds per tow. Exploitable biomass for the Kamishak District in Cook Inlet is also calculated using areas swept methods, however, input data are from an ADF&G survey conducted in 1984.

Registration areas exhibiting sporadic catch and effort preclude estimation of TACs by the above methods. To allow exploratory fishing in these registration areas, the State established conservative CBLs under which some exploratory scallop fishing may occur but at levels that are not likely to overharvest the

scallop stocks in those areas. Similarly, the Council recommended a conservation approach. In registration areas for which no specified numerical amount is provided for the TAC in Table 1, the TAC would equal the total weight of shucked scallop meats that can be harvested under the CBLs specified for those areas. In no case would the total amount harvested in all areas result in a harvest that would exceed the upper end of the OY range.

The only known commercially viable scallop beds in Southeast Alaska are found in the Fairweather Grounds in District 16. For purposes of scallop management, this district has been shifted from the Registration Area A (Southeastern) to the adjacent Registration Area D (Yakutat). Because there are no other known commercially viable scallop beds in Registration Area A, the TAC for this area is set at zero. Vessel operators wishing to explore for new scallop beds in this area would apply for an experimental fishing permit under § 672.6 of this part.

Under Amendment 1, scallops may be taken in Registration Areas D (Yakutat) and E (Prince William Sound) from 1200 hours, A.l.t., January 10 through 2400 hours, A.l.t., June 30. Should NMFS approve Amendment 1 to the scallop FMP, the TACs and CBLs for these registration areas would become available January 10, 1997.

TABLE 1.—SCALLOP TAC AMOUNTS FOR THE PERIOD [INSERT EFFECTIVE DATE OF FINAL RULE] THROUGH JUNE 30, 1997 IN POUNDS OF SHUCKED SCALLOP MEATS BY SCALLOP REGISTRATION AREA AND DISTRICT

[Kilograms in parentheses][1]

Scallop registration area	TAC
Registration Area A (Southeastern)	Zero.
Registration Area D (Yakutat):	
District 16	35,000 (15,880 kg).
All other districts	250,000 (113,430 kg).
Registration Area E (Prince William Sound)	50,000 (22,686 kg).
Registration Area H (Cook Inlet):	
Kamishak District	20,000 (9,074 kg).
Registration Area K (Kodiak)	400,000 (181,488 kg).
Registration Area O (Dutch Harbor)	170,000 (77,132 kg).

[1] Scallop TAC amounts for Registration Areas M, Q, R and all other districts in Registration Area H (other than the Kamishak District) equal the total weight of shucked scallop meat taken under the CBLs established for those areas in Table 2, not to exceed a total of 875,000 lb (396.9 mt).

Proposed Crab Bycatch Limits

Table 2 shows proposed CBLs for the period [insert effective date of final rule] through June 30, 1997. These proposed CBLS reflect the most recent CBLs established by the State. In Registration areas or districts where red king crab or tanner crab abundance is sufficient to support a commercial crab fishery, the State established CBLs for the scallop fishery at 1 percent of the most recent estimate of red king crab or Tanner crab abundance. In registration areas or districts where red king crab or tanner crab abundance is insufficient to support a commercial fishery, the State established CBLs at 0.5 percent of the most recent estimate of red king crab or Tanner crab abundance.

In the Bering Sea Registration Area, the Council recommended that the annual red king crab CBL be set within a range of 500 to 3,000 crab. Because red king crab abundance in the Bering Sea is at an all time low, NMFS proposes a CBL at the lower end of the Council's range, or 500 crab. Proposed Tanner Crab CBLs for the Bering Sea Registration Area are based on percentages of total crab abundance approved by the Council.

TABLE 2.—CRAB BYCATCH LIMITS FOR THE PERIOD [INSERT EFFECTIVE DATE OF FINAL RULE] THROUGH JUNE 30, 1997 IN NUMBERS OF CRABS BY SCALLOP REGISTRATION AREA AND DISTRICT

Scallop registration area	Red king	C. bairdi	C. opilio
Area E (Prince William Sound)	.....	630	.....
Area H (Cook Inlet):			
Kamishak District	40	15,900	.....
Outer/Eastern Districts	98	2,170	.....
Area K (Kodiak):			
Shelikof District	22	16,100	.....
Northeast District	66	130,000	.....
Area M (Alaska Peninsula)	435	22,800	.....
Area O (Dutch Harbor)	10	10,700	.....
Area Q (Bering Sea)	500	257,000	275,000
Area R (Adak)	50	10,000	.....

Classification

Section 304(a)(1)(D) of the Magnuson Act requires NMFS publish proposed regulations within 15 days of receipt of an FMP amendment and regulations from a Council. At this time NMFS has not determined that the FMP amendment that this rule would implement is consistent with the national standards, other provisions of the Magnuson Act, and other applicable laws. NMFS, in making that determination, will take into account the data, views, and comments received during the comment period.

This proposed rule has been determined to be not significant for the purposes of E.O. 12866.

An RIR was prepared for this proposed rule that describes the management background, the purpose and need for action, the management action alternatives, and the social

impacts of the alternatives. The RIR also estimates the total number of small entities affected by this action and analyzes the economic impact on those small entities. Copies of the RIR can be obtained from NMFS (see **ADDRESSES**).

The Council has prepared an IRFA as part of the RIR, which describes the impact this proposed rule would have on small entities, if adopted. The analysis shows that the economic effects of this proposed rule to the regulated community would be significant and positive in that it would repeal the closure of Federal waters to fishing for scallops. In 1994, 86 percent of the scallops harvested off Alaska were taken from Federal waters and 11 of the 16 vessels harvesting scallops participated in no other fishery. A copy of this analysis is available from the Council (see **ADDRESSES**).

List of Subjects in 50 CFR Part 673

Fisheries.

Dated: May 6, 1996.

Gary Matlock,

Program Management Officer, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR part 673 is proposed to be amended as follows:

PART 673—SCALLOP FISHERY OFF ALASKA

1. Part 673 is revised to read as follows:

Sec.
673.1 Purpose and scope.
673.2 Definitions.
673.3 Prohibitions.
673.4 Gear limitations.
673.5 Registration areas.
673.6 General limitations.
673.7 Inseason adjustments.
673.8 Seasons.
673.9 Observer requirements.

Authority: 16 U.S.C. 1801 *et seq.*

§ 673.1 Purpose and scope.

(a) These regulations implement the Fishery Management Plan for the Scallop Fishery off Alaska (FMP). The FMP was prepared by the North Pacific Fishery Management Council (Council) under the Magnuson Act.

(b) Regulations in this part govern commercial fishing for scallops in the Federal waters off Alaska.

(c) State of Alaska laws that are consistent with the regulations in this part are not preempted for vessels registered under the laws of the State fishing for scallops in the Federal waters off Alaska.

§ 673.2 Definitions.

In addition to the definitions in the Magnuson Act and in §§ 620.2 and 672.2 of this chapter, the terms used in this part have the following meanings:

CBL means crab bycatch limit.

Scallop(s) means any scallop species of the family Pectinidae, including without limitation weathervane scallops (*Patinopectin caurinus*).

Scallop dredge means gear consisting of a mouth frame attached to a holding bag constructed of metal rings or any other modification to this design that can be or is used in the harvest of scallops, or the taking of scallops by means of such gear.

Shucking machine means any mechanical device that automatically removes the meat or the adductor muscle from the shell.

§ 673.3 Prohibitions.

In addition to the general prohibitions specified in § 620.7 of this chapter, it is unlawful for any person to violate any provision of this part.

§ 673.4 Gear limitations.

(a) The inside ring diameter on all dredges used or carried by a vessel fishing for weathervane scallops (*Patinopectin caurinus*) must be 4 inches (10.16 cm) or larger.

(b) The inside ring diameter on all dredges used or carried by a vessel fishing for scallops other than weathervane scallops must be 3 inches (7.62 cm) or larger.

(c) No person may use chafing gear or other devices that decrease the legal inside ring diameter of a scallop dredge.

(d) Except as provided in paragraph (e) of this section, no more than two scallop dredges may be operated at one time from a vessel, and the opening of a scallop dredge must be equal to or less than 15 ft (4.57 m) wide.

(e) In the Kamishak, Southern, and Central Districts of Scallop Registration Area H defined under § 673.5, no more than one scallop dredge may be operated at one time from a vessel, and the opening of a dredge may not be more than 6 ft (1.83 m) in width.

(f) Scallops must be shucked by hand only. A shucking machine must not be on board a vessel that is fishing for scallops or that has scallops on board.

(g) No vessel fishing for scallops in Federal waters may have aboard more than 12 persons, exclusive of ADF&G or NMFS observers.

§ 673.5 Registration areas.

For the purpose of managing the scallop fishery, the Federal waters off Alaska and adjacent State waters are divided into nine scallop registration areas. Three scallop registration areas are further subdivided into districts. The scallop registration areas and districts are defined as follows:

(a) *Registration Area A* (Southeastern) has as its southern boundary the international boundary at Dixon Entrance, and as its northern boundary Loran-C line 7960–Y–29590, which intersects the western tip of Cape Fairweather at 58°47′58″ N. lat., 137°56′30″ W. long., except for ADF&G District 16 defined under paragraph (b) of this section.

(b) *Registration Area D* (Yakutat) has as its western boundary the longitude of Cape Suckling (143°53′ W. long.), and as its southern boundary Loran-C line 7960–Y–29590, which intersects the western tip of Cape Fairweather at 58°47′58″ N. lat., 137°56′30″ W. long., and ADF&G District 16 defined as all waters north of a line projecting west from the southernmost tip of Cape Spencer and south of a line projecting southwest from the westernmost tip of Cape Fairweather.

(c) *Registration Area E* (Prince William Sound) has as its western boundary the longitude of Cape Fairfield (148°50′ W. long.), and its eastern boundary the longitude of Cape Suckling (143°53′ W. long.).

(d) *Registration Area H* (Cook Inlet) has as its eastern boundary the longitude of Cape Fairfield (148°50′ W. long.) and its southern boundary the latitude of Cape Douglas (58°52′ N. lat.).

(1) *Northern District:* North of a line extending from Boulder Point at 60 46′23″ N. lat., to Shell Platform C, then to a point on the west shore at 60°46′23″ N. lat.

(2) *Central District:* All waters between a line extending from Boulder Point at 60°46′23″ N. lat., to Shell Platform C, to a point on the west shore at 60°46′23″ N. lat., and the latitude of Anchor Point Light (59°46′12″ N. lat.).

(3) *Southern District*: All waters enclosed by a line from Anchor Point Light west to 59°46′12″ N. lat., 152°20′ W. long., then south to 59°03′25″ N. lat., 152°20′ W. long., then in a northeasterly direction to the tip of Cape Elizabeth at 59°09′30″ N. lat., 151°53′ W. long., then from the tip of Cape Elizabeth to the tip of Point Adam at 59°15′20″ N. lat., 151°58′30″ W. long.

(4) *Kamishak Bay District:* All waters enclosed by a line from 59°46′12″ N. lat., 153°00′30″ W. long., then east to 59°46′12″ N. lat., 152°20′ W. long., then south to 59°03′25″ N. lat., 152°20′ W. long., then southwesterly to Cape Douglas (58°52′ N. lat.). The seaward boundary of the Kamishak Bay District is 3 nautical miles seaward from the shoreline between a point on the west shore of Cook Inlet at 59°46′12″ N. lat., 153°00′30″ W. long., and Cape Douglas at 58°52′ N. lat., 153°15′ W. long., including a line three nautical miles

seaward from the shorelines of Augustine Island and Shaw Island, and including the line demarking all state waters shown on NOAA chart 16640, 21st Ed., May 5, 1990.

(5) *Barren Island District*: All waters enclosed by a line from Cape Douglas (58°52′ N. lat.) to the tip of Cape Elizabeth at 59°09′30″ N. lat., 151°53′ W. long., then south to 58°52′ N. lat., 151°53′ W. long., then west to Cape Douglas.

(6) *Outer District*: All waters enclosed by a line from the tip of Point Adam to the tip of Cape Elizabeth, then south to 58°52′ N. lat., 151°53′ W. long., then east to the longitude of Aligo Point (149°44′33″ W. long.), then north to the tip of Aligo Point.

(7) *Eastern District*: All waters east of the longitude of Aligo Point (149°44′33″ W. long.), west of the longitude of Cape Fairfield (148°50′ W. long.), and north of 58°52′ N. lat.

(e) *Registration Area K* (Kodiak) has as its northern boundary the latitude of Cape Douglas (58°52′ N lat.), and as its western boundary the longitude of Cape Kumlik (157°27′ W. long.).

(1) *Northeast District*: All waters northeast of a line extending 168° from the easternmost tip of Cape Barnabas, east of a line from the northernmost tip of Inner Point to the southernmost tip of Afognak Point, east of 152°30′ W. long. in Shuyak Strait, and east of the longitude of the northernmost tip of Shuyak Island (152°20′ W. long.).

(2) *Southeast District*: All waters southwest of a line extending 168° from the easternmost tip of Cape Barnabas and east of a line extending 222° from the southernmost tip of Cape Trinity.

(3) *Southwest District*: All waters west of a line extending 222° from the southernmost tip of Cape Trinity, south of a line from the westernmost tip of Cape Ikolik to the southernmost tip of Cape Kilokak and east of the longitude of Cape Kilokak (156°19′ W. long.).

(4) *Semidi Island District*: All waters west of the longitude of Cape Kilokak at 156°19′ W. long. and east of the longitude of Cape Kumlik at 157°27′ W. long.

(5) *Shelikof District*: All waters north of a line from the westernmost tip of Cape Ikolik to the southernmost tip of Cape Kilokak, west of a line from the northernmost tip of Inner Point to the southernmost tip of Afognak Point, west of 152°30′ W. long., in Shuyak Strait, and west of the longitude of the northernmost tip of Shuyak Island (152°20′ W. long.).

(f) *Registration Area M* (Alaska Peninsula) has as its eastern boundary the longitude of Cape Kumlik (157°27′ W. long.), and its western boundary the longitude of Scotch Cap Light. The registration area also includes all waters of Bechevin Bay and Isanotski Strait south of a line from the easternmost tip of Chunak Point to the westernmost tip of Cape Krenitzen.

(g) *Registration Area O* (Dutch Harbor) has as its northern boundary the latitude of Cape Sarichef (54°36′ N. lat.), as its eastern boundary the longitude of Scotch Cap Light, and as its western boundary 171°W. long., excluding the waters of Statistical Area Q.

(h) *Registration Area Q* (Bering Sea) has as its southern boundary a line from Cape Sarichef (54°36′ N. lat.), to 54°36′ N. lat., 171°W. long., to 55°30′ N. lat., 171°W. long., to 55°30′ N. lat., 173°30′ E. long., as its northern boundary the latitude of Point Hope (68°21′ N. lat.).

(i) *Registration Area R* (Adak) has as its eastern boundary 171° W. long., and as its northern boundary 55°30′ N. lat.

§ 673.6 General limitations.

(a) *Harvest limits*—(1) *General*. NMFS will establish total allowable catch (TAC) amounts and CBLs for the scallop fishery off Alaska according to the procedures described under this section. The total annual TAC amount for scallops off Alaska will be established within the OY range of 0–1.8 million lb (0–815.5 mt) of shucked scallop meats.

(2) *Annual TACs*. (i) The annual TACs for scallops in Registration Areas A, D, E, H, K, and O will be established as a weight in pounds of shucked scallop meats based on a review of the following:

(A) Assessments of the biological condition of each scallop species. Assessments will include, where practicable, updated estimates of MSY and ABC; historical catch trends and current catch statistics, reviews of alternative harvesting strategies; and relevant information relating to changes in scallop markets.

(B) Socioeconomic considerations that are consistent with the goals and objectives of the FMP.

(ii) The annual TACs in Registration Areas M, Q, and R will equal the weight in pounds of shucked scallop meats harvested under CBLs specified for these areas under paragraph (3) of this section. The sum of TACs in Registration Areas M, Q, and R may not exceed an amount equal to the upper end of the OY range minus the sum of the TACs in Registration Areas A, D, E, H, K, and O.

(iii) Annual scallop TACs will be specified for the 12-month time period extending from July 1 through June 30 of the following year. An annual TAC amount is available for harvest only for the registration area or district specified, only during the applicable season set out in § 673.8, and only if no closure or other restriction or limitation is applicable.

(3) *Crab bycatch limits*. (i) CBLs may be specified for red king crab and Tanner crab species for any registration area or district.

(ii) Except as provided under paragraph (a)(3)(iii) of this section, annual CBLs will be based on the biological condition of each crab species, historical bycatch rates in the scallop fishery, and other socioeconomic considerations that are consistent with the goals and objectives of the FMP.

(iii) Annual CBLs in Registration Area Q will equal the following amounts:

(A) The CBL for red king crab caught while conducting any fishery for scallops will be specified within the range of 500 to 3,000 crab based on the considerations listed in paragraph (a)(3)(ii) of this section.

(B) The CBL for *Chionoecetes opilio* Tanner crab caught while conducting any fishery for scallops is 0.003176 percent of the best available estimate of *C. opilio* abundance in Registration Area Q.

(C) The CBL for *Chionoecetes bairdi* Tanner crab caught while conducting any fishery for scallops is 0.13542 percent of the best available estimate of *C. bairdi* abundance in Registration Area Q.

(iv) Annual CBLs will be specified for the 12-month time period from July 1 through June 30 of the following year. An annual CBL may be utilized only for the registration area or district specified, only if any applicable TAC amount is available for harvest, only during the applicable season set out in § 673.8, and only if no closure or other limitation or restriction is applicable.

(b) *Specifications*. The following procedure is established for specifying TAC amounts and CBLs:

(1) On an annual basis, prior to the April Council meeting, the Council will distribute a summary of the State's most recent TAC and CBL recommendations and supporting documentation to the public through its mailing list, as well as provide copies of the recommendations, documentation, and the annual Stock Assessment and Fishery Evaluation (SAFE) report to the public upon request. The Council will notify the public of its intent to develop final recommendations at the April Council meeting and solicit public comment both before and during the April Council meeting.

(2) Following the April Council meeting, the Council will submit its TAC and CBL recommendations along

with rationale and supporting information to NMFS for review and implementation.

(3) As soon as practicable after receiving recommendations from the Council, NMFS will publish in the Federal Register annual specifications of TAC amounts and CBLs for the succeeding 12-month period extending from July 1 through June 30 of the following year.

(c) *Notices of closure*. (1) If the Director, Alaska Region, NMFS, determines that a TAC or CBL specified under paragraphs (a) and (b) of this section has been or will be reached, NMFS will publish notification in the Federal Register prohibiting the taking and retention of scallops in the Federal waters of the registration area or district where the notification is applicable.

(2) It is unlawful for any person to conduct any fishing for scallops contrary to the notification of closure issued pursuant to this paragraph.

(d) *Closed areas*. It is unlawful for any person to dredge for scallops in any Federal waters off Alaska that are closed to fishing with trawl gear or non pelagic trawl gear under §§ 672.24(d), 672.24(e), 675.22(a) 675.22(b), 674.22(f), and 675.24(g) of this chapter.

§ 673.7 Inseason adjustments.

(a) Inseason adjustments may be issued by NMFS to implement the closure, extension, opening, or reopening of a season in all or part of a scallop registration area; and the adjustment of TAC amounts or CBLs.

(b) Determinations for any inseason adjustment authorized under paragraph (a) of this section must be consistent with §§ 672.22 (a) and (b) of this chapter.

(c) Procedures for making inseason adjustments are specified at § 672.22(c) of this chapter.

(d) It is unlawful for any person to conduct any fishing for scallops contrary to an inseason adjustment issued pursuant to this section.

§ 673.8 Seasons.

(a) Fishing for scallops in the Federal waters off Alaska is authorized from 0001 hours, A.l.t., July 1, through 2400 hours, A.l.t., June 30, subject to the other provisions of this part, except as provided in paragraphs (b) through (d).

(b) Scallops may only be taken in the Federal waters of Scallop Registration Areas A, D, and E from 1200 hours, A.l.t., January 10 through 2400 hours, A.l.t., June 30, subject to the other provisions of this part.

(c) Scallops may only be taken in the Federal waters of Scallop Registration Areas K, M, O, Q, and R from 1200 hours, A.l.t., July 1 through 1200 hours, A.l.t., February 15 of the following year, subject to the other provisions of this part.

(d) Scallops may only be taken in the Federal waters of the Kamishak District of Scallop Registration Area H from 1200 hours, A.l.t., August 15 through 1200 hours, A.l.t., October 31, subject to the other provisions of this part.

§ 673.9 Observer requirements.

(a) Except as provided in paragraph (c) of this section, vessels must carry a NMFS-certified or ADF&G-certified scallop observer at all times while fishing for scallops in Federal waters.

(b) An operator of a vessel required to carry an observer must meet all of the requirements specified at §§ 677.10(c) and 677.10(g) of this chapter.

(c) Vessels less than 80 ft (24.4 m) length overall are exempt from the requirements of this section while fishing for scallops in the Federal waters of Registration Area H.

[FR Doc. 96–11773 Filed 5–07–96; 3:34 pm]

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Notices

Federal Register
Vol. 61, No. 92
Friday, May 10, 1996

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Forest Service

Newspapers Used for Publication of Legal Notice, Comment and Appeal of Decisions for Pacific Northwest Region, Oregon and Washington

AGENCY: Forest Service, USDA.

ACTION: Notice.

SUMMARY: This notice lists the newspapers that will be used by all ranger districts, forests, and the Regional Office of the Pacific Northwest Region to publish legal notice of all decisions subject to appeal under 36 CFR Parts 215 and 217 and to publish notice for public comment and notice of decisions subject to the provisions of 36 CFR Part 215. The intended effect of this action is to inform interested members of the public which newspapers will be used to publish the legal notice for public comment or decision. This allows the public to receive constructive notice of a decision, to provide clear evidence of timely notice, and to achieve consistency in administering the appeal process.

DATES: Publication of legal notices in the listed newspapers will begin with proposals for public comment or decisions subject to appeal that are made on or after April 30, 1996. The list of newspapers will remain in effect until another notice is published in the Federal Register.

FOR FURTHER INFORMATION CONTACT: Jim L. Schuler, Regional Appeals Coordinator, Pacific Northwest Region, P.O. Box 3623, Portland, Oregon 97208–3623, phone: (503) 326–2322.

SUPPLEMENTARY INFORMATION: Responsible Officials in the Pacific Northwest Region will give legal notice of decisions that may be subject to appeal under 36 CFR Part 215 and 217 in the following newspapers which are listed by Forest Service administrative units. Where more than one newspaper is listed for any unit, the first newspaper listed is the principal newspaper, which shall be used to constitute legal evidence that the agency has given timely and constructive notice for comment and for decisions that may be subject to administrative appeal. The timeframe for appeal shall be based on the date of publication of a notice of decision in the principal newspaper.

The newspapers to be used are as follows:

Pacific Northwest Regional Office

Pacific Northwest Regional Forester decisions on Oregon National Forests:
The Oregonian, Portland, Oregon
Pacific Northwest Regional Forester decisions on Washington, National Forests:
The Seattle Post-Intelligencer, Seattle, Washington
Columbia Gorge National Scenic Area Manager decisions:
The Oregonian, Portland, Oregon

Oregon National Forests

Deschutes National Forest

Deschutes Forest Supervisors decisions:
The Bulletin, Bend, Oregon
Bend District Ranger decisions:
The Bulletin, Bend, Oregon
Crescent District Ranger decisions:
The Bulletin, Bend, Oregon
Fort Rock District Ranger decisions:
The Bulletin, Bend, Oregon
Sister District Ranger decisions:
Sisters Nugget, Sisters, Oregon
Bend Pine Nursery Managers decisions:
The Bulletin, Bend, Oregon
Redmond Air Center Managers decisions:
The Bulletin, Bend, Oregon

Fremont National Forest

Fremont Forest Supervisor decisions:
Herald and News, Klamath Falls, Oregon
Newspapers providing additional notice of Forest Supervisor decisions:
Lake County Examiner, Lakeview, Oregon
The Bulletin, Bend, Oregon
Bly District Ranger decisions:
Herald and News, Klamath Falls, Oregon
Lakeview District Ranger decisions:
Lake County Examiner, Lakeview, Oregon
Paisley District Ranger decisions:
Lake County Examiner, Lakeview, Oregon
Silver Lake District Ranger decisions:
Herald and News, Klamath Falls, Oregon
Newspaper providing additional notice of Silver Lake decisions:
The Bulletin, Bend, Oregon

Malheur National Forest

Malheur Forest Supervisor decisions:
Blue Mountain Eagle, John Day, Oregon
Bear Valley District Ranger decisions:
Blue Mountain Eagle, John Day, Oregon
Burns District Ranger decisions:
Burns Times Herald, Burns, Oregon
Long Creek District Ranger decisions:
Blue Mountain Eagle, John Day, Oregon
Prairie City District Ranger decisions:
Blue Mountain Eagle, John Day, Oregon

Mt Hood National Forest

Mt Hood Forest Supervisor decisions:
The Oregonian, Portland, Oregon
Barlow District Ranger decisions:
The Oregonian, Portland, Oregon
Bear Springs District Ranger decisions:
The Oregonian, Portland, Oregon
Clackamas District Ranger decisions:
The Oregonian, Portland, Oregon
Columbia Gorge District Ranger decisions:
The Oregonian, Portland, Oregon
Estacada District Ranger decisions:
The Oregonian, Portland, Oregon
Hood River District Ranger decisions:
The Oregonian, Portland, Oregon
Zigzag District Ranger decisions:
The Oregonian, Portland, Oregon

Ochoco National Forest

Ochoco Forest Supervisor decisions:
The Bulletin, Bend, Oregon
Newspapers providing additional notice of Forest Supervisor decisions:
Burns Times/Herald, Burns, Oregon
Central Oregonian, Prineville, Oregon
Big Summit District Ranger decisions:
The Bulletin, Bend, Oregon
Crooked River National Grassland District Ranger decisions:
The Bulletin, Bend, Oregon
Newspapers providing additional notice of Grassland decisions:
Madras Pioneer, Madras, Oregon
Paulina District Ranger decisions:
The Bulletin, Bend, Oregon
Newspapers providing additional

notice of Paulina decisions:
Blue Mountain Eagle, John Day, Oregon
Prineville District Ranger decisions:
The Bulletin, Bend, Oregon
Newspapers providing additional notice of Prineville decisions:
Central Oregonian, Prineville, Oregon
Snow Mountain District Ranger decisions:
The Bulletin, Bend, Oregon
Newspapers providing additional notice of Snow Mountain decisions:
Burns Times/Herald, Burns, Oregon

Rogue River National Forest

Rogue River Forest Supervisor decisions:
Mail Tribune, Medford, Oregon
Applegate District Ranger decisions:
Mail Tribune, Medford, Oregon
Ashland District Ranger decisions:
Mail Tribune, Medford, Oregon
Butte Falls District Ranger decisions:
Mail Tribune, Medford, Oregon
J. Herbert Stone Nursery Managers decisions:
Mail Tribune, Medford, Oregon
Prospect District Ranger decisions:
Mail Tribune, Medford, Oregon

Siskiyou National Forest

Siskiyou Forest Supervisor decisions:
Grants Pass Courier, Grants Pass, Oregon
Chetco District Ranger decisions:
Curry Coastal Pilot, Brookings, Oregon
Galice District Ranger decisions:
Grants Pass Courier, Grants Pass, Oregon
Gold Beach District Ranger decisions:
Curry County Reporter, Gold Beach, Oregon
Illinois Valley District Ranger decisions:
Grants Pass Courier, Grants Pass, Oregon
Powers District Ranger decisions:
The World, Coos Bay, Oregon
Newspaper providing additional notice of Powers decisions:
Curry County Reporter, Gold Beach, Oregon

Siuslaw National Forest

Siuslaw Forest Supervisor decisions:
Corvallis Gazette-Times, Corvallis, Oregon
Alsea District Ranger decisions:
Corvallis Gazette-Times, Corvallis, Oregon
Hebo District Ranger decisions:
Headlight Herald, Tillamook, Oregon
Mapleton District Ranger decisions:
Siuslaw News, Florence, Oregon
Oregon Dunes National Recreation Area Manager decisions:
The World, Coos Bay, Oregon
Waldport District Ranger decisions:
Newport News times, Newport, Oregon

Umatilla National Forest

Umatilla Forest Supervisor decisions:
East Oregonian, Pendleton, Oregon
Heppner District Ranger decisions:
East Oregonian, Pendleton, Oregon
North Fork John Day District Ranger decisions:
East Oregonian, Pendleton, Oregon
Pomeroy District Ranger decisions:
East Oregonian Pendleton, Oregon
Walla Walla District Ranger decisions:
East Oregonian Pendleton, Oregon

Umpqua National Forest

Umpqua Forest Supervisor decisions:
The News-Review, Roseburg, Oregon
Cottage Grove District Ranger decisions:
The News-Review, Roseburg, Oregon
Diamond Lake District Ranger decisions:
The News-Review, Roseburg, Oregon
North Umpqua District Ranger decisions:
The News-Review, Roseburg, Oregon
Tiller District Ranger decisions:
The News-Review, Roseburg, Oregon
Dorena Tree Improvement Center Manager decisions:
The News-Review, Roseburg, Oregon

Wallowa-Whitman National Forest

Wallowa-Whitman Forest Supervisor decisions:
Baker City Herald, Baker City, Oregon
Baker District Ranger decisions:
Baker City Herald, Baker City, Oregon
Eagle Cap District Ranger decisions:
Wallowa County Chieftain, Enterprise, Oregon
Hells Canyon National Recreation Area Ranger decisions:
Occurring in Oregon—
Wallowa County Chieftain, Enterprise, Oregon
Occurring in Idaho—
Lewiston Morning Tribune, Lewiston, Idaho
La Grande District Ranger decisions:
The Observer, La Grande, Oregon
Pine District Ranger decisions:
Baker City Herald, Baker City, Oregon
Unity District Ranger decisions:
Baker City Herald, Baker City, Oregon
Wallowa Valley District Ranger decisions:
Wallowa County Chieftain, Enterprise, Oregon

Willamette National Forest

Willamette Forest Supervisor decisions:
Register-Guard, Eugene, Oregon
Newspapers providing additional notice of Forest Supervisor decisions:
Salem Statesman-Journal, Salem, Oregon
Albany Democrat Hearld, Albany, Oregon
Blue River District Ranger decisions:
Register-Guard, Eugene, Oregon
Newspapers providing additional notice of Blue River decisions:
Salem Statesman-Journal, Salem, Oregon
Albany Democrat Herald, Albany, Oregon
Detroit District Ranger decisions:
Register-Guard, Eugene, Oregon
Newspapers providing additional notice of Detroit decisions:
Salem Statesman-Journal, Salem, Oregon
Albany Democrat Herald, Albany, Oregon
Lowell District Ranger decisions:
Register-Guard, Eugene, Oregon
Newspapers providing additional notice of Lowell decisions:
Salem Statesman-Journal, Salem, Oregon
Albany Democrat Herald, Albany, Oregon
McKenzie District Ranger decisions:
Register-Guard, Eugene, Oregon
Newspapers providing additional notice of McKenzie decisions:
Salem Statesman-Journal, Salem, Oregon
Albany Democrat Herald, Albany, Oregon
Oakridge District Ranger decisions:
Register-Guard, Eugene, Oregon
Newspapers providing additional notice of Oakridge decisions:
Salem Statesman-Journal, Salem, Oregon
Albany Democrat Herald, Albany, Oregon
Rigdon District Ranger decisions:
Register-Guard, Eugene, Oregon
Newspapers providing additional notice of Rigdon decisions:
Salem Statesman-Journal, Salem, Oregon
Albany Democrat Herald, Albany, Oregon
Sweet Home District Ranger decisions:
Register-Guard, Eugene, Oregon
Newspapers providing additional notice of Sweet Home decisions:
Salem Statesman-Journal, Salem, Oregon
Albany Democrat Herald, Albany, Oregon

Winema National Forest

Winema Forest Supervisor decisions:
Herald and News, Klamath Falls, Oregon
Chemult District Ranger decisions:
Herald and News, Klamath Falls, Oregon
Chiloquin District Ranger decisions:
Herald and News, Klamath Falls, Oregon
Klamath District Ranger decisions:

Herald and News, Klamath Falls, Oregon

Washington National Forests

Colville National Forest

Colville Forest Supervisor decisions:
Statesman-Examiner, Colville, Washington
Colville District Ranger decisions:
Statesman-Examiner, Colville, Washington
Kettle Falls District Ranger decisions:
Statesman-Examiner, Colville, Washington
Newport District Ranger decisions:
Newport Miner, Newport, Washington
Republic District Ranger decisions:
Republic News Miner, Republic, Washington
Sullivan Lake District Ranger decisions:
Newport Miner, Newport, Washington

Gifford Pinchot National Forest

Gifford Pinchot Forest Supervisor decisions:
Columbian, Vancouver, Washington
Mount St. Helens National Volcanic Monument Manager decisions:
Columbian, Vancouver, Washington
Mt. Adams District Ranger decisions:
Enterprise, White Salmon, Washington
Packwood District Ranger decisions:
Chronicle, Chehalis, Washington
Randle District Ranger decisions:
Chronicle, Chehalis, Washington
Wind River District Ranger decisions:
Columbian, Vancouver, Washington

Mt. Baker-Snoqualmie National Forest

Mt. Baker-Snoqualmie Forest Supervisor decisions:
Seattle Post-Intelligencer, Seattle, Washington
Darrington District Ranger decisions:
Everett Herald, Everett, Washington
Mt. Baker District Ranger decisions:
Skaqit Valley Herald, Mt. Vernon, Washington
North Bend District Ranger decisions:
Valley Record, North Bend, Washington
Skykomish District Ranger decisions:
Everett Herald, Everett, Washington
White River District Ranger decisions:
Enumclaw Courier Herald, Enumclaw, Washington

Okanagon National Forest

Okanagon Forest Supervisor decisions:
The Wenatchee World, Wenatchee, Washington
Tonasket District Ranger decisions:
The Gazette-Tribune, Oroville, Washington
Twisp District Ranger decisions:
Methow Valley News, Twisp, Washington
Winthrop District Ranger decisions:
Methow Valley News, Twisp, Washington

Olympic National Forest

Olympic Forest Supervisor decisions:
The Olympian, Olympia, Washington
Newspapers providing additional notice of Forest Supervisor decisions:
Mason County Journal, Shelton, Washington
Daily World, Aberdeen, Washington
Peninsula Daily News, Port Angeles, Washington
Bremerton Sun, Bremerton, Washington
Hood Canal District Ranger decisions:
Mason County Journal, Shelton, Washington
Quilcene District Ranger decisions:
Peninsula Daily News, Port Angeles, Washington
Newspaper providing additional notice of Quilcene decisions:
Bremerton Sun, Bremerton, Washington
Quinault District Ranger decisions:
The Daily World, Aberdeen, Washington
Soleduck District Ranger decisions:
The Forks Forum, Forks, Washington

Wenatchee National Forest

Wenatchee Forest Supervisor decisions:
The Wenatchee World, Wenatchee, Washington
Newspaper providing additional notice of Forest Supervisor decisions:
The Yakima Herald-Republic, Yakima, Washington
Chelan District Ranger decisions:
The Wenatchee World, Wenatchee, Washington
Newspaper providing additional notice of Chelan decisions:
The Yakima Herald-Republic, Yakima, Washington
Cle Elum District Ranger decisions:
The Wenatchee World, Wenatchee, Washington
Newspaper providing additional notice of Cle Elum decisions:
The Yakima Herald-Republic, Yakima, Washington
Entiat District Ranger decisions:
The Wenatchee World, Wenatchee, Washington
Newspaper providing additional notice of Entiat decisions:
The Yakima Herald-Republic, Yakima, Washington
Lake Wenatchee District Ranger decisions:
The Wenatchee World, Wenatchee, Washington
Newspaper providing additional notice of Lake Wenatchee decisions:
The Yakima Herald-Republic, Yakima, Washington
Leavenworth District Ranger decisions:
The Wenatchee World, Wenatchee, Washington
Newspaper providing additional notice of Leavenworth decisions:
The Yakima Herald-Republic, Yakima, Washington
Naches District Ranger decisions:
The Wenatchee World, Wenatchee, Washington
Newspaper providing additional notice of Naches decisions:
The Yakima Herald-Republic, Yakima, Washington

Dated: May 3, 1996.

Richard A. Ferraro,

Deputy Regional Forester.

[FR Doc. 96–11709 Filed 5–9–96; 8:45 am]

BILLING CODE 3410–11–M

Newpapers To Be Used for Publication of Legal Notice of Appealable Decisions and Publication of Notice on Proposed Actions for Southern Region; Alabama, Kentucky, Georgia, Tennessee, Florida, Louisiana, Mississippi, Virginia, West Virginia, Arkansas, Oklahoma, North Carolina, South Carolina, Texas, Puerto Rico

AGENCY: Forest Service, USDA.

ACTION: Notice.

SUMMARY: Deciding Officers in the Southern Region will publish notice of decisions subject to administrative appeal under 36 CFR parts 215 and 217 in the legal notice section of the newspapers listed in the Supplementary Information section of this notice. As provided in 36 CFR 215.5(a) and 36 CFR 217.5(d), the public shall be advised, through Federal Register notice, of the principal newspaper to be utilized for publishing legal notices of decisions. Newspaper publication of notices of decisions is in addition to direct notice of decisions to those who have requested notice in writing and to those known to be interested in or affected by a specific decision.

In addition, the Responsible Officials in the Southern Region will also publish notice of proposed actions under 36 CFR 215 in the newspapers that are listed in the Supplementary Information section of this notice. As provided in 36 CFR 215.5(a), the public shall be advised, through Federal Register notice, of the principal newspapers to be utilized for publishing notices on proposed actions.

DATES: Use of these newspapers for purposes of publishing legal notices of decisions subject to appeal under 36 CFR Parts 215 and 217, and notices of

proposed actions under 36 CFR part 215 shall begin on or after the date of this publication.

FOR FURTHER INFORMATION CONTACT: Jean Paul Kruglewicz, Regional Appeals Coordinator, Southern Region, Planning and Budget, 1720 Peachtree Road NW, Atlanta, Georgia 30367–9102, Phone: 404–347–4867.

SUPPLEMENTARY INFORMATION: Deciding Officers in the Southern Region will give legal notice of decisions subject to appeal under 36 CFR part 217 and Responsible Official in the Southern Region will give notice of decisions subject to appeal under 36 CFR Part 215 in the following newspapers which are listed by Forest Service administrative unit. Responsible Officials in the Southern Region will also give notice of proposed actions under 36 CFR part 215 in the following principal newspapers which are listed by Forest Service administrative unit. The timeframe for comment on a proposed action shall be based on the date of publication of the notice of the proposed action in the principal newspaper. The timeframe for appeal shall be based on the date of publication of the legal notice of the decision in the principal newspaper for both 36 CFR 215 and 217.

Where more than one newspaper is listed for any unit, the first newspaper listed is the principal newspaper that will be utilized for publishing the legal notices of decisions. Additional newspapers listed for a particular unit are those newspapers the Deciding Officer expects to use for purposes of providing additional notice. The following newspapers will be used to provide notice.

Southern Region

Regional Forester Decisions:
- Affecting National Forest System lands in more than one state of the 13 states of the Southern Region and the Commonwealth of Puerto Rico.
- *Atlanta Journal,* published daily in Atlanta, GA
- Affecting National Forest System lands in only one state of the 13 states of the Southern Region and the Commonwealth of Puerto Rico or one Ranger District will appear in the principal newspaper elected by the National Forest(s) of that state or Ranger District.

National Forests in Alabama, Alabama

Forest Supervisor Decisions:
- *Montgomery Advertiser,* published daily in Montgomery, AL

District Ranger Decisions:
- Bankhead Ranger District: *Northwest Alabamian,* published weekly (Monday & Thursday) in Haleyville, AL
- Conecuh Ranger District: *The Andalusia Star,* published daily (Tuesday through Saturday) in Andalusia, AL
- Oakmulgee Ranger District, *The Tuscaloosa News,* published daily in Tuscaloosa, AL
- Shoal Creek Ranger District: *The Anniston Star,* published daily in Anniston, AL
- Talladega Ranger District: *The Daily Home,* published daily in Talladega, AL
- Tuskegee Ranger District: *Tuskegee News,* published weekly (Thursday) in Tuskegee, AL

Caribbean National Forest, Puerto Rico

Forest Supervisor Decisions:
- *El Nuevo Dia,* published daily in Spanish in San Juan, PR
- *San Juan Star,* published daily in San Juan, PR

District Ranger Decisions:
- *El Horizonte,* published weekly (Wednesday) in Fajardo, PR

Chattahoochee-Oconee National Forest, Georgia

Forest Supervisor Decisions:
- *The Times,* published daily in Gainesville, GA

District Ranger Decisions:
- Armuchee Ranger District: *Walker County Messenger,* published bi-weekly (Wednesday & Friday) in LaFayette, GA
- Toccoa Ranger District: *The News Observer* published weekly (Wednesday) in Blue Ridge, GA
- Brasstown Ranger District: *North Georgia News,* published weekly (Wednesday) in Blairsville, GA
- Tallulah Ranger District: *Clayton Tribune,* published weekly (Thursday) in Clayton, GA
- Chattooga Ranger District: *Northeast Georgian,* published weekly (Tuesday) in Cornelia, GA
- *Toccoa Record,* published weekly (Thursday) in Toccoa, GA
- *White County News,* published weekly (Thursday) in Cleveland, GA
- Cohutta Ranger District: *Chatsworth Times,* published weekly (Wednesday) in Chatsworth, GA
- Oconee Ranger District: *Monticello News,* published weekly (Thursday) in Monticello, GA

Cherokee National Forest, Tennessee

Forest Supervisor Decisions:
- *Knoxville News Sentinel,* published daily in Knoxville, TN (covering McMinn, Monroe, and Polk Counties)
- *Johnson City Press,* published daily in Johnson City, TN (covering Carter, Cocke, Greene, Johnson, Sullivan, Unicoi and Washington Counties)

District Ranger Decisions:
- Ocoee Ranger District: *Polk County News,* published weekly (Wednesday) in Benton, TN
- Hiwassee Ranger District: *Daily Post-Athenian,* published daily (Monday–Friday) in Athens, TN
- Tellico Ranger District: *Monroe County Advocate,* published weekly (Thursday) in Sweetwater, TN
- Nolichucky Ranger District: *Greeneville Sun,* published daily (Monday–Saturday) in Greeneville, TN
- Unaka Ranger District: *Johnson City Press,* published daily in Johnson City, TN
- Watauga Ranger District: *Elizabethton Star,* published daily (Sunday—Friday) in Elizabethton, TN

Daniel Boone National Forest, Kentucky

Forest Supervisor Decisions:
- *Lexington Herald-Leader,* published daily in Lexington, KY

District Ranger Decisions:
- Morehead Ranger District: *Morehead News,* published bi-weekly (Tuesday and Friday) in Morehead, KY
- Stanton Ranger District: *The Clay City Times,* published weekly (Thursday) in Stanton, KY
- Berea Ranger District: *Jackson County Sun,* published weekly (Thursday) in McKee, KY
- London Ranger District: *The Sentinel-Echo,* published tri-weekly (Monday, Wednesday, and Friday) in London, KY
- Somerset Ranger District: *Commonwealth-Journal,* published daily (Sunday through Friday) in Somerset, KY
- Stearns Ranger District: *McCreary County Record,* published weekly (Tuesday) in Whitley City, KY
- Redbird Ranger District: *Manchester Enterprise,* published weekly (Thursday) in Manchester, KY

National Forests in Florida, Florida

Forest Supervisor Decisions:
- *The Tallahassee Democrat,* published daily in Tallahassee, FL

District Ranger Decisions:
- Apalachicola Ranger District: *The Liberty Journal,* published weekly (Wednesday) in Bristol, FL
- Lake George Ranger District: *The Ocala Star Banner,* published daily in Ocala, FL
- Osceola Ranger District: *The Lake City*

Reporter, published daily (Monday–Saturday) in Lake City, FL
Seminole Ranger District: *The Daily Commercial*, published daily in Leesburg, FL
Wakulla Ranger District: *The Tallahassee Democrat*, published daily in Tallahassee, FL

Francis Marion & Sumter National Forest, South Carolina

Forest Supervisor Decisions:
The State, published daily in Columbia, SC
District Ranger Decisions:
Enoree Ranger District: *Newberry Observer*, published tri-weekly (Monday, Wednesday, and Friday) Newberry, SC
Andrew Pickens Ranger District: *Seneca Journal and Tribune*, published bi-weekly (Wednesday and Friday) in Seneca, SC
Long Cane Ranger District: *The State*, published daily in Columbia, SC
Wambaw Ranger District: *News and Courier*, published daily in Charleston, SC
Witherbee Ranger District: *News and Courier*, published daily in Charleston, SC

George Washington and Jefferson National Forests, Virginia

Forest Supervisor Decisions:
Roanoke Times, published daily in Roanoke, VA
District Ranger Decisions:
Lee Ranger District: *Shenandoah Valley Herald*, published weekly (Wednesday) in Woodstock, VA
Warm Springs Ranger District: *The Recorder*, published weekly (Thursday) in Monterey, VA
Pedlar Ranger District: *News-Gazette*, published weekly (Wednesday) in Lexington, VA
James River Ranger District: *Virginian Review*, published daily (except Sunday) in Covington, VA
Deerfield Ranger District: *Daily News Leader*, published daily in Staunton, VA
Dry River Ranger District: *Daily News Record*, published daily (except Sunday)in Harrisonburg, VA
Blacksburg Ranger District: *Roanoke Times*, published daily in Roanoke, VA
Monroe Watchman, published weekly (Thursday) in Union, WV (only for those decisions in West VA—notice will be published in the *Roanoke Times* and *Monroe Watchman*.)
Glenwood Ranger District: *Roanoke Times*, published daily in Roanoke, VA
New Castle Ranger District: *Roanoke Times*, published daily in Roanoke, VA
Monroe Watchman, published weekly (Thursday) in Union, WV (only for those decisions in West VA—notice will be published in the *Roanoke Times* and *Monroe Watchman*.)
Mount Rogers National Recreation Area: *Bristol Herald Courier*, published daily in Bristol, VA
Clinch Range District: *Kingsport-Times News*, published daily in Kingsport, TN
Wythe Ranger District: *Southwest Virginia Enterprise*, published bi-weekly (Wednesday and Saturday) in Wytheville, VA

Kisatchie National Forest, Louisiana

Forset Supervisor Decisions:
Alexandria Daily Town Talk, published daily in Alexandria, LA
District Ranger Decisions:
Caney Ranger District: *Minden Press Herald*, published daily in Minden, LA
Homer Guardian Journal, published weekly (Wednesday) in Homer, LA
Catahoula Ranger District: *Alexandria Daily Town Talk*, published daily in Alexandria, LA
Colfax Chronicle, published weekly (Wednesday) in Colfax, LA
Evangeline Ranger District: *Alexandria Daily Town Talk*, published daily in Alexandria, LA
Kisatchie Ranger District: *Natchitoches Times*, published daily (Tuesday—Friday and on Sunday) in Natchitoches, LA
Vernon Ranger District: *Leesville Leader*, published daily in Leesville, LA
Winn Ranger District: *Winn Parish Enterprise*, published weekly (Wednesday) in Winnfield, LA

National Forests in Mississippi, Mississippi

Forest Supervisor Decisions:
Clarion-Ledger, published daily in Jackson, MS
District Ranger Decisions:
Bienville Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Biloxi Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Black Creek Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Bude Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Chickasawhay Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Delta Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Holly Springs Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Homochitto Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Strong River Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Tombigbee Ranger District: *Clarion-Ledger*, published daily in Jackson, MS
Ashe-Erambert Project: *Clarion-Ledger*, published daily in Jackson, MS

National Forests in North Carolina, North Carolina

Forest Supervisor Decisions:
The Asheville Citizen-Times, published daily in Asheville, NC
District Ranger Decisions:
Cheoah Ranger District: *Graham Star*, published weekly (Thursday) in Robbinsville, NC
Croatan Ranger District: *The Sun Journal*, published weekly (Sunday through Friday) in New Bern, NC
French Broad Ranger District: *The Asheville Citizen-Times*, published daily in Asheville, NC
Grandfather Ranger District: *McDowell News*, published daily in Marion, NC
Highlands Ranger District: *The Highlander*, published weekly (May–Oct Tues & Fri; Oct–April Tues only) in Highlands, NC
The Crossroads Chronicle, published weekly (May–Oct Tues & Fri; Oct–April Tues only) in Cashiers, NC
The Sylva Herald, published weekly on Thursday in Sylva, NC
Pisgah Ranger District: *The Asheville Citizen-Times*, published daily in Asheville, NC
Toecane Ranger District: *The Asheville Citizen-Times*, published daily in Asheville, NC
Tusquitee Ranger District: *Cherokee Scout*, published weekly (Wednesday) in Murphy, NC
Uwharrie Ranger District: *Montgomery Herald*, published weekly (Wednesday) in Troy, NC
Wayha Ranger District: *The Franklin Press*, published bi-weekly (Wednesday and Friday) in Franklin, NC

Ouachita National Forest, Arkansas, Oklahoma

Forest Supervisor Decisions:
Arkansas Democrat-Gazette, published daily in Little Rock, AR
District Ranger Decisions:
Caddo Ranger District: *Arkansas Democrat-Gazette*, published daily in Little Rock, AR
Cold Springs Ranger District: *Arkansas Democrat-Gazette*,

published daily in Little Rock, AR
Fourche Ranger District: *Arkansas Democrat-Gazette,* published daily in Little Rock, AR
Jessieville Ranger District: *Arkansas Democrat-Gazette,* published daily in Little Rock, AR
Mena Ranger District: *Arkansas Democrat-Gazette,* published daily in Little Rock, AR
Oden Ranger District: *Arkansas Democrat-Gazette,* published daily in Little Rock, AR
Poteau Ranger District: *Arkansas Democrat-Gazette,* published daily in Little Rock, AR
Winona Ranger District: *Arkansas Democrat-Gazette,* published daily in Little Rock, AR
Womble Ranger District: *Arkansas Democrat-Gazette,* published daily in Little Rock, AR
Choctaw Ranger District: *Tulsa World,* published daily in Tulsa, OK
Kiamichi Ranger District: *Tulsa World,* published daily in Tulsa, OK
Tiak Ranger District: *Tulsa World,* published daily in Tulsa, OK

Ozark-St. Francis National Forest: Arkansas

Forest Supervisor Decisions:
The Courier, published daily (Sunday through Friday) in Russellville, AR
District Ranger Decisions:
Sylamore Ranger District: *Stone County Leader,* published weekly (Tuesday) in Mountain View, AR
Buffalo Ranger District: *Newton County Times,* published weekly (Thursday) in Jasper, AR
Bayou Ranger District: *The Courier,* published daily (Sunday through Friday) in Russellville, AR
Pleasant Hill Ranger District: *Johnson County Graphic,* published weekly (Wednesday) in Clarksville, AR
Boston Mountain Ranger District: *Southwest Times Record,* published daily in Fort Smith, AR
Magazine Ranger District: *Southwest Times Record,* published daily in Forth Smith, AR
St. Francis Ranger District: *The Daily World,* published daily (Sunday through Friday) in Helena, AR

National Forest and Grasslands in Texas, Texas

Forest Supervisor Decisions:
The Lufkin Daily News, published daily in Lufkin, TX
District Ranger Decisions:
Angelina National Forest: *The Lufkin Daily News,* published daily in Lufkin, TX
Davy Crockett National Forest: *The Lufkin Daily News,* published daily in Lufkin, TX
Sabine National Forest: *The Lufkin Daily News,* published daily in Lufkin, TX
Sam Houston National Forest: *The Courier,* published daily in Conroe, TX
Caddo & LBJ National Grasslands: *Denton Record-Chronicle,* published daily in Denton, TX

Dated: May 3, 1996.

Bruce L. Jewel,

Acting Regional Forester.

[FR Doc. 96–11708 Filed 5–9–96; 8:45 am]

BILLING CODE 3410–11–M

Grain Inspection, Packers and Stockyards Administration

Posting of Stockyards

Pursuant to the authority provided under section 302 of the Packers and Stockyards Act (7 U.S.C. 202), it was ascertained that the livestock markets named below were stockyards as defined by section 302(a). Notice was given to the stockyard owners and to the public as required by section 302(b), by posting notices at the stockyards on the dates specified below, that the stockyards were subject to the provisions of the Packers and Stockyards Act, 1921, as amended (7 U.S.C. 181 *et seq.*).

Facility No., name, and location of stockyard	Date of posting
AR–170—Cattlemen's Livestock, Auction, Inc., Harrison, Arkansas.	March 7, 1996.
MI–150—Stockbridge Horse Auction, Stockbridge, Michigan.	March 15, 1996.
TX–344—Sonora Livestock Auction, Inc., South Sonora, Texas.	March 8, 1996.

Done at Washington, D.C. this 2nd day of May 1996.

Daniel L. Van Ackeren,

Director, Livestock Marketing Division, Packers and Stockyards Programs.

[FR Doc. 96–11647 Filed 5–9–96; 8:45 am]

BILLING CODE 3410–KD–P

Proposed Posting of Stockyard

The Grain Inspection, Packers and Stockyards Administration, United States Department of Agriculture, has information that the livestock market named below is a stockyard as defined in Section 302 of the Packers and Stockyards Act (7 U.S.C. 202), and should be made subject to the provisions of the Packers and Stockyards Act, 1921, as amended (7 U.S.C. 181 *et seq.*).

OH–151—Producers Livestock Association, Gallipolis, Ohio

Pursuant to the authority under Section 302 of the Packers and Stockyards Act, notice is hereby given that it is proposed to designate the stockyard named above as a posted stockyard subject to the provisions of said Act.

Any person who wishes to submit written data, views or arguments concerning the proposed designation may do so by filing them with the Director, Livestock Marketing Division, Grain Inspection, Packers and Stockyards Administration, Room 3408–South Building, U. S. Department of Agriculture, Washington, D.C. 20250 by May 21, 1996.

All written submissions made pursuant to this notice will be made available for public inspection in the office of the Director of the Livestock Marketing Division during normal business hours.

Done at Washington, D.C. this 6th day of May 1996.

Daniel L. Van Ackeren,

Director, Livestock Marketing Division, Packers and Stockyards Programs.

[FR Doc. 96–11646 Filed 5–9–96; 8:45 am]

BILLING CODE 3410–KD–P

BROADCASTING BOARD OF GOVERNORS

Sunshine Act Meeting

DATE AND TIME: May 14, 1996; 9:00 a.m.

PLACE: Cohen Building, 330 Independence Avenue, S.W., First Floor Auditorium, Washington, D.C. 20547.

OPEN MEETING: The members of the Broadcasting Board of Governors will meet in open session to exchange views with employees of the International Broadcasting Bureau, USIA, and the public on the policies and activities of U.S. international broadcasting. An open dialogue is welcome. Any members of the public wishing to attend should contact the IBB Office of External Affairs at (202) 619–2538.

CLOSED MEETING: At 11:00 a.m., The members of the Broadcasting Board of Governors (BBG) will meet in closed session in room 3709 to address internal procedural, budgetary, and personnel issues, as well as sensitive foreign policy issues relating to potential options in the U.S. international broadcasting field. This meeting is closed because if open it likely would either disclose matters that would be properly classified to be kept secret in

the interest of foreign policy under the appropriate executive order (5 U.S.C. 552b. (c)(1)) or would disclose information the premature disclosure of which would be likely to significantly frustrate implementation of a proposed agency action. (5 U.S.C. 552b (c)(9)(B)). In addition, part of the discussion will relate solely to the internal personnel issues of the BBG or the International Broadcasting Bureau. (5 U.S.C. 552b.(c)(2) and (6)).

CONTACT PERSON FOR MORE INFORMATION: Persons interested in obtaining more information should contact Barbara Floyd at (202) 401–3736.

Dated: May 8, 1996.

David W. Burke,

Chairman.

[FR Doc. 96–11925 Filed 5–8–96; 1:14 pm]

BILLING CODE 6155–01–M

COMMITTEE FOR PURCHASE FROM PEOPLE WHO ARE BLIND OR SEVERELY DISABLED

Procurement List; Additions

AGENCY: Committee for Purchase From People Who Are Blind or Severely Disabled.

ACTION: Additions to the procurement list.

SUMMARY: This action adds to the Procurement List services to be furnished by nonprofit agencies employing persons who are blind or have other severe disabilities.

EFFECTIVE DATE: June 10, 1996.

ADDRESSES: Committee for Purchase From People Who Are Blind or Severely Disabled, Crystal Square 3, Suite 403, 1735 Jefferson Davis Highway, Arlington, Virginia 22202–3461.

FOR FURTHER INFORMATION CONTACT: Beverly Milkman (703) 603–7740.

SUPPLEMENTARY INFORMATION: On March 15 and 22, 1996, the Committee for Purchase From People Who Are Blind or Severely Disabled published notices (61 F.R. 10733 and 11811) of proposed additions to the Procurement List.

After consideration of the material presented to it concerning capability of qualified nonprofit agencies to provide the services and impact of the additions on the current or most recent contractors, the Committee has determined that the services listed below are suitable for procurement by the Federal Government under 41 U.S.C. 46–48c and 41 CFR 51–2.4.

I certify that the following action will not have a significant impact on a substantial number of small entities. The major factors considered for this certification were:

1. The action will not result in any additional reporting, recordkeeping or other compliance requirements for small entities other than the small organizations that will furnish the services to the Government.

2. The action will not have a severe economic impact on current contractors for the services.

3. The action will result in authorizing small entities to furnish the services to the Government.

4. There are no known regulatory alternatives which would accomplish the objectives of the Javits-Wagner-O'Day Act (41 U.S.C. 46–48c) in connection with the services proposed for addition to the Procurement List.

Accordingly, the following services are hereby added to the Procurement List:

Janitorial/Custodial

Portsmouth Naval Shipyard, Buildings H–29 and 86, Kittery, Maine

Naval Undersea Warfare Center, Buildings 1319 and 1320, Newport, Rhode Island

Medical Transcription

U.S. Naval Hospital, North Charleston, South Carolina

Parts Sorting

Oklahoma City Air Logistics Center, Tinker Air Force Base, Oklahoma

Switchboard Operation

Department of Veterans Affairs Medical Center, Buffalo, New York

This action does not affect current contracts awarded prior to the effective date of this addition or options that may be exercised under those contracts.

Beverly L. Milkman,

Executive Director.

[FR Doc. 96–11769 Filed 5–9–96; 8:45 am]

BILLING CODE 6353–01–P

Procurement List; Proposed Additions

AGENCY: Committee for Purchase From People Who Are Blind or Severely Disabled.

ACTION: Proposed Additions to Procurement List.

SUMMARY: The Committee has received proposals to add to the Procurement List services to be furnished by nonprofit agencies employing persons who are blind or have other severe disabilities.

COMMENTS MUST BE RECEIVED ON OR BEFORE: June 10, 1996.

ADDRESSES: Committee for Purchase From People Who Are Blind or Severely Disabled, Crystal Square 3, Suite 403, 1735 Jefferson Davis Highway, Arlington, Virginia 22202–3461.

FOR FURTHER INFORMATION CONTACT: Beverly Milkman (703) 603–7740.

SUPPLEMENTARY INFORMATION: This notice is published pursuant to 41 U.S.C. 47(a)(2) and 41 CFR 51–2.3. Its purpose is to provide interested persons an opportunity to submit comments on the possible impact of the proposed actions.

If the Committee approves the proposed additions, all entities of the Federal Government (except as otherwise indicated) will be required to procure the services listed below from nonprofit agencies employing persons who are blind or have other severe disabilities.

I certify that the following action will not have a significant impact on a substantial number of small entities. The major factors considered for this certification were:

1. The action will not result in any additional reporting, recordkeeping or other compliance requirements for small entities other than the small organizations that will furnish the services to the Government.

2. The action does not appear to have a severe economic impact on current contractors for the services.

3. The action will result in authorizing small entities to furnish the services to the Government.

4. There are no known regulatory alternatives which would accomplish the objectives of the Javits-Wagner-O'Day Act (41 U.S.C. 46–48c) in connection with the services proposed for addition to the Procurement List.

Comments on this certification are invited. Commenters should identify the statement(s) underlying the certification on which they are providing additional information.

The following services have been proposed for addition to Procurement List for production by the nonprofit agencies listed:

Recycling Service

Basewide, Dobbins Air Reserve Base, Georgia

NPA: Georgia Diversified Industries, Inc., Cartersville, Georgia

Switchboard Operation

Oklahoma City Air Logistics Center, Tinker Air Force Base, Oklahoma

NPA: The Oklahoma League for the Blind, Oklahoma City, Oklahoma

Beverly L. Milkman,

Executive Director.

[FR Doc. 96–11771 Filed 5–9–96; 8:45 am]

BILLING CODE 6353–01–P

Proposed Additions to the Procurement List; Correction

In the document appearing on page 18571, F.R. Doc. 96–10409, in the issue of April 26, 1996, in the first column, under the Trousers, Wet Weather, it should read (Remaining 50% of the Government's requirement) rather than (Remaining 25% of the Government's requirement).

Beverly L. Milkman,

Executive Director.

[FR Doc. 96–11770 Filed 5–9–96; 8:45 am]

BILLING CODE 6353–01–P

DEPARTMENT OF DEFENSE

Department of the Air Force

Air Force Academy Board of Visitors; Meeting

Pursuant to Section 9355, Title 10 United States Code, the Air Force Academy Board of Visitors will meet at the U.S. Air Force Academy, Colorado, 12–14 July 1996. The purpose of the meeting is to consider morale and discipline, the curriculum, instruction, physical equipment, fiscal affairs, academic methods, and other matters relating to the Academy.

A portion of the meeting will be open to the public on the morning of 13 July 1996. Other portions of the meeting will be closed to the public to discuss matters listed in the subsections (2), (4), and (6) of section 552b(c), Title 5, United States Code. These closed sessions will included attendance at cadet training programs and discussions with cadets, military staff, and faculty officers involving personal information and opinion, the disclosure of which would result in a clearly unwarranted invasion of personal privacy. Closed sessions will also include executive sessions involving discussions of personal information, including financial information, and information relating solely to internal personnel rules and practices of the Board of Visitors and the Academy. Meeting sessions will be held to various facilities throughout the cadet area.

For further information contact my Project Officers, Capt Timothy D. Miller or Ms. Deborah Mercurio, 2304 Cadet Drive, Suite 350, USAF Academy CO 80840–5002, DSN 259–3450 or 719–472–3450.

Patsy J. Conner,

Air Force Federal Register Liaison Officer.

[FR Doc. 96–11664 Filed 5–9–96; 8:45 am]

BILLING CODE 3910–01–M

Department of the Army

Notice of Availability of Technology for Non-Exclusive, Exclusive or Partially Exclusive Licensing

AGENCY: U.S. Army Research Laboratory, Physical Sciences Directorate, DoD.

ACTION: Notice.

SUMMARY: In accordance with 37 CFR 404.6, Section 11(a)(2) of the Federal Technology Transfer Act of 1986 (Public Law 99–502) and section 207 of title 35, United States Code, announcement is made of the availability of the following technology for licensing. The Department of the Army as represented by the Army Research Laboratory, Physical Sciences Directorate wishes to license the technology described below in a non-exclusive, exclusive or partially exclusive manner to any part interested in manufacturing, using, and/or selling devices or processes covered by this technology. This technology has been assigned to the United States of America as represented by the Secretary of the Army, Washington, DC.

FOR FURTHER INFORMATION CONTACT: For additional information regarding this notice please contact Mr. William H. Anderson, Intellectual Property Law Division, Attention: AMSEL–LG–L, Ft. Monmouth, New Jersey 07703 or telephone (908) 532–4112.

SUPPLEMENTARY INFORMATION: The Electro-chemical Capacitor technology involves the preparation of electrode materials and the assembly of other components together to provide energy with a power higher than that of batteries.

Gregory D. Showalter,

Army Federal Register Liaison Officer.

[FR Doc. 96–11712 Filed 5–9–96; 8:45 am]

BILLING CODE 3710–08–M

Corps of Engineers

Available Surplus Real Property at Fort Chaffee Military Reservation, Located in Fort Smith, Sebastian County, AR

AGENCY: U.S. Army Corps of Engineers, Little Rock District.

ACTION: Notice.

SUMMARY: This notice identifies the surplus real property located at Fort Chaffee Military Reservation, Arkansas. Fort Chaffee is located 15 miles from Interstate 40 and is 15 miles east of Fort Smith, Arkansas. A municipal airport and rail network are in close proximity.

FOR FURTHER INFORMATION CONTACT: For additional information regarding particular properties identified in this Notice (i.e., acreage, floor plans, existing sanitary facilities, exact street address), contact Ms. Peggy Boismier, Army Corps of Engineers, 700 West Capitol, Room 6317, Little Rock, Arkansas 72201–3221 (telephone (501) 324–5716, fax (501) 324–7166) or Mr. Warren Johnson, Base Transition Coordinator, HQ USAG, ATTN: ATZR–ZC, Fort Chaffee, Arkansas 72905–5000 (telephone (501) 484–2083, fax (501) 484–2055).

SUPPLEMENTARY INFORMATION: This surplus property is available under the provisions of the Federal Property and Administrative Services Act of 1949 and the Base Closure Community Redevelopment and Homeless Assistance Act of 1994 (Public Law 103–421). Notices of interest should be forwarded to the Fort Chaffee Redevelopment Authority (FCRA), W.R. Harper, Sebastian County Judge, County Courthouse, 35 South 6th Street, Fort Smith, Arkansas 72901, (501) 783–6139, or by fax at (501) 784–1550.

The surplus real property at Fort Chaffee contains 6,206 acres and includes 515 buildings totaling 1,881,670 square feet. Present use of the buildings includes administrative, supply, vehicle maintenance, warehouse/storage, dining, hospital/ward and barracks

The effective date of the Determination of Surplus is April 5, 1996.

Gregory D. Showalter,

Army Federal Register Liaison Officer.

[FR Doc. 96–11711 Filed 5–9–96; 8:45 am]

BILLING CODE 3710–DL–M

Notice of Availability of Surplus Land and Buildings in Accordance With Public Law 103–421 Located at Fort Ritchie Military Reservation, Cascade, MD

AGENCY: U.S. Army Corps of Engineers, DoD.

ACTION: Notice of availability.

SUMMARY: This notice identifies the surplus real property located at the Fort Ritchie Military Reservation, Cascade, MD. The property is located in Washington County, Northeast of Hagerstown in the community of Cascade, MD at the intersection of routes 550 to 491.

FOR FURTHER INFORMATION CONTACT: For more information regarding the particular property identified in this Notice (i.e., acreage, floor plans, existing sanitary facilities, exact location), contact Mr. Gerry Bresee, Real Estate Division, Army Corps of Engineers, P.O. Box 1715, Baltimore, MD 21203

(telephone 410–962–5173, fax 410–962–0866).

SUPPLEMENTARY INFORMATION: This surplus is available under the provisions of the Federal Property and Administrative Services Act of 1945 and the Base Closure Community Redevelopment and Homeless Assistance Act of 1994. Notices of interest should be forwarded to Mr. Robert Sweeney, Executive Director, Ft. Ritchie Local Redevelopment Authority, P.O. Box 699, Cascade, MD 21719, telephone (301) 241–4050, fax (301) 241–4141.

The surplus real property totals approximately 635.65 acres and contains 252 buildings totaling 1,384,000 square feet of space. Current range of uses include administrative, residential, retail, open recreation and special purpose space. Future uses may include generally the same types of uses.

Gregory D. Showalter,

Army Federal Register Liaison Officer.

[FR Doc. 96–11713 Filed 5–9–96; 8:45 am]

BILLING CODE 3710–41–M

Intent To Prepare a Draft Environmental Impact Statement (DEIS) for a Proposed Storm Damage Reduction and Beach Erosion Control Project on Brigantine Island, Atlantic County, NJ

AGENCY: U.S. Army Corps of Engineers, DoD.

ACTION: Notice of intent.

SUMMARY: The action being taken is an evaluation of the alternatives for storm damage reduction and the control of further erosion on Brigantine Island, New Jersey. The purpose of any consequent work would be to provide shore property protection and to stabilize the shoreline at the predetermined width.

FOR FURTHER INFORMATION CONTACT: Questions regarding the DEIS should be addressed to Ms. Beth Brandreth, (215) 656–6558, U.S. Army Corps of Engineers, CENAP–PL–E, Wanamaker Building, 100 Penn Square East, Philadelphia, Pennsylvania 19107–3390.

SUPPLEMENTARY INFORMATION:

1. Proposed Action

a. The draft document evaluates a study area approximately 7 miles in length, extending from Brigantine Inlet to Absecon Inlet. The study area encompasses Brigantine Island, which contains the City of Brigantine and the North Brigantine State Nature Area. The beaches along this island have been subject to erosion by storms, tidal inundation, and wave action. One potential offshore sand borrow source, located in the vicinity of Brigantine Inlet, will be investigated in this study.

b. The authorities for the proposed project are the resolutions adopted by the Committee on Public Works and Transportation of the U.S. House of Representatives and the Committee on Environmental and Public Works of the U.S. Senate in December 1987.

2. Alternatives

In addition to the no action alternative, the alternatives considered for storm damage reduction and erosion control will fall into structural and non-structural categories. The structural measures to correct the beach erosion include bulkheads, seawalls, revetments, offshore breakwaters, groins, beach nourishment, perched beach, submerged reef with beachfill, and offshore submerged feeder berms. Non-structural measures include flood insurance, developmental regulations, and evacuation.

3. Scoping

a. Numerous studies and reports addressing beach erosion along the New Jersey Coast were conducted by the Corps of Engineers. The most recent study for this area is a Reconnaissance Report: Brigantine Inlet to Great Egg Harbor Inlet Reconnaissance Study (February 1992), which identified a number of problem areas where erosion was negatively impacting the adjacent shorelines. This study identified Brigantine Island as one of the primary areas to be recommended for further study in the feasibility phase.

b. The scoping process is on-going and has involved preliminary coordination with Federal, State, and local agencies. Participation of the general public and other interested parties and organizations will be invited by means of a public notice.

c. The significant issues and concerns that have been identified include the impacts of the project on aquatic biota, water quality, intertidal habitat, shallow water habitat, and cultural resources.

4. Availability

It is estimated that the DEIS will be made available to the public in October 1997.

Robert L. Callegari,

Chief, Planning Division.

[FR Doc. 96–11714 Filed 5–9–96; 8:45 am]

BILLING CODE 3710–GR–M

Department of the Navy

Notice of Closed Meeting of Board of Visitors to the United States Naval Academy

Pursuant to the provisions of the Federal Advisory Committee Act (5 U.S.C. App. 2), notice is hereby given that the Board of Visitors to the United States Naval Academy will meet on May 13, 1996, at Alumni Hall, United States Naval Academy, Annapolis, MD, at 8:30 a.m. The meetings will be closed to the public.

The purpose of the meeting is to make such inquiry as the Board shall deem necessary into the state of morale and discipline, the curriculum, instruction, physical requirements, fiscal affairs, and academic methods of the Naval Academy. During the meeting these inquiries will relate to the internal personnel rules and practices of the Academy, may involve review of on-going criminal investigations, and include discussions of personal information the disclosure of which would constitute a clearly unwarranted invasion of personal privacy if the meeting was open to the public. Accordingly, the Secretary of the Navy has determined in writing that this meeting shall be closed to the public because the meeting will be concerned with matters as outlined in sections 552b(c) (2), (5), (6), (7), and (9) of Title 5, United States Code.

For further information concerning this meeting contact: Lieutenant Commander Adam S. Levitt, U.S. Navy, Secretary to the Board of Visitors, Office of the Superintendent, United States Naval Academy, Annapolis, MD 21402–5000, Telephone Number: (410) 293–1503.

Dated: May 1, 1996.

M.A. Waters,

LCDR, JAGC, USN, Alternate Federal Register Liaison Officer.

[FR Doc. 96–11805 Filed 5–9–96; 8:45 am]

BILLING CODE 3810–FF–P

Notice of Open Meeting of Board of Advisors to the President, Naval War College, Newport, Rhode Island

Pursuant to the provisions of the Federal Advisory Committee Act (5 U.S.C. app.), notice is given that the Board of Advisors to the President, Naval War College, will meet on 29 and 30 May 1996 in Room 210, Conolly Hall, Naval War College, 686 Cushing Road, Newport, Rhode Island. The meeting will commence at 8:30 a.m. on 29 May and terminate at approximately 12:00 p.m. on 30 May. The purpose of the

meeting is to elicit the advice of the Board on educational, doctrinal, and research policies and programs. The agenda will consist of presentations and discussions on the curriculum, programs and plans of the College, and is open to the public. For further information contact: Mrs. Mary E. Estabrooks, Assistant to the Dean of Academics, Naval War College, 686 Cushing Road, Newport, RI 02841–1207. Telephone Number (401) 841–3589.

Dated: May 1, 1996.

M.A. Waters,

LCDR, JAGC, USN, Alternate Federal Register Liaison Officer.

[FR Doc. 96–11806 Filed 5–9–96; 8:45 am]

BILLING CODE 3810–FF–P

DEPARTMENT OF EDUCATION

[CFDA No.: 84.004C]

Desegregation of Public Education—State Educational Agency Desegregation Program; Notice of Cancellation of New Awards for Fiscal Year (FY) 1996

SUMMARY: On December 20, 1995, the Department of Education published a notice in the Federal Register (60 FR 65644) inviting applications for new awards for FY 1996 for the Desegregation of Public Education—State Educational Agency Program. On March 27, 1996, a notice was published in the Federal Register (61 FR 13485) extending the closing date for receipt of applications to May 9, 1996. The purpose of this notice is to advise potential applicants that this competition has been cancelled due to lack of funds.

FOR FURTHER INFORMATION CONTACT: Adell S. Washington, U.S. Department of Education, 600 Independence Avenue SW., Suite 4500 Portals, Washington, DC 20202–6140. Telephone (202) 260–2495. Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 between 8 a.m. and 8 p.m., Eastern time, Monday through Friday.

Information about the Department's funding opportunities, including copies of application notices for discretionary grant competitions, can be viewed on the Department's electronic bulletin board (ED Board), telephone (202) 260–9950; on the Internet Gopher Server at GOPHER.ED.GOV (under Announcements, Bulletins, and Press Releases); or on the World Wide Web at (http://www.ed.gov/money.html). However, the official application notice for a discretionary grant competition is the notice published in the Federal Register.

Program Authority: 42 U.S.C. 2000c–1–9

Dated: May 6, 1996.

Gerald N. Tirozzi,

Assistant Secretary for Elementary and Secondary Education.

[FR Doc. 96–11735 Filed 5–9–96; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EG96–62–000]

ANP Operations Company; Notice of Application for Commission Determination of Exempt Wholesale Generator Status

May 6, 1996.

On May 2, 1996, ANP Operations Company (''Applicant''), a Delaware corporation, whose address is 10000 Memorial Drive, Suite 500, Houston, Texas 77024, filed with the Federal Energy Regulatory Commission an application for determination of exempt wholesale generator status pursuant to Part 365 of the Commission's Regulations.

Applicant intends to operate an approximate 149 MW gas-fired, dispatchable, combined-cycle, independent power production facility located near Milford, Massachusetts (the ''Facility''). The Facility is owned by Milford Power Limited Partnership (''Owner'') who sells electric power from the Facility at wholesale.

Any person desiring to be heard concerning the application for exempt wholesale generator status should file a motion to intervene or comments with the Federal Energy Regulatory Commission, 888 First Street N.E., Washington, D.C. 20426, in accordance with §§ 385.211 and 385.214 of the Commission's Rules of Practice and Procedure. The Commission will limit its consideration of comments to those that concern the adequacy or accuracy of the application. All such motions and comments should be filed on or before May 23, 1996 and must be served on the applicant. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11676 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–221–000]

ANR Pipeline Company; Notice of Annual System Cashout Report

May 6, 1996.

Take notice that on May 1, 1996, ANR Pipeline Company (ANR) tendered for filing its annual report of the net revenues attributable to the operation of its cashout program.

ANR states that this filing is ANR's second annual System Cashout Report since the implementation of Order No. 636, and covers the period January 1, 1995 to December 31, 1995. The Net Cashout Activity for the twelve month period ending December 31, 1995 is ($386.833). As provided in Section 15.5(b) of ANR's General Terms and Conditions of its FERC Gas Tariff, Second Revised Volume No. 1, this amount will be carried forward and applied to the next succeeding redetermination of Net Cashout Activity for the calendar year ended December 31, 1996.

Any person desiring to be heard or to protest this filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 in accordance with Section 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11677 Filed 5–9–96' 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–222–000]

Columbia Gas Transmission Corporation; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, Columbia Gas Transmission Corporation (Columbia) tendered the filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, the following tariff sheets to become effective June 1, 1996.

Original Sheet No. 99E
Original Sheet No. 99F

Columbia states that the instant filing is being submitted pursuant to Article VII, Section C, Accrued-But-Not-Paid Gas Costs, of the ''Customer Settlement'' in Docket No. GP94–02, et al., approved by the Commission on June 15, 1995 (71 FERC ¶ 61,337 (1955)). The Customer Settlement became effective on November 28, 1995, when the Bankruptcy Court's November 1, 1995, order approving Columbia's Plan of Reorganization became final. Under the terms of Article VII, Section C, Columbia is entitled to recover amounts for Accrued-But-Not-Paid Gas Costs. As directed by Article VII, Section C, the tariff sheets contained herein are being filed in accordance with Section 39 of the General Terms and Conditions of the Tariff, to direct bill the Accrued-But-Not-Paid Gas Costs that have been paid subsequent to November 28, 1995. The instant filing reflects Accrued-But-Not-Paid Gas Costs in the amount of $1,388,133.11 plus applicable FERC interest of $16,383.33. This is Columbia's second filing pursuant to Article VII, Section C, and Columbia reserves the right to make the appropriate additional filings pursuant to that provision. The allocation factors on Appendix F of the Customer Settlement were used as prescribed by Article VII, Section C.

Columbia also agrees to make available for this filing the data that it was required to provide in its April 11, 1996 compliance filing in Docket No. RP96–140 pursuant to a protective agreement.

Any person desiring to be heard or to protest this filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Sections 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11678 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TM96–9–23–000]

Eastern Shore Natural Gas Company; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996 Eastern Shore Natural Gas Company (ESNG) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1, certain substitute revised tariff sheets in the above captioned docket, with a proposed effective date of February 1, 1996.

ESNG states that the revised tariff sheets included herein are being filed pursuant to Section 24 of the General Terms and Conditions of the ESNG's Gas Tariff to reflect changes in ESNG's jurisdictional storage rates. ESNG states that the instant filing is being made to ''track'' changes in Columbia Gas Transmission Corporation's (Columbia) storage service rates. Upon the recent close of ESNG's February, 1996 monthly accounting cycle it became apparent that ESNG had inadvertently failed to track the proper storage service rates from Columbia for February, 1996. The substitute tariff sheets included herein are being filed to correct this error.

As background to the instant filing, on August 1, 1995 Columbia filed a Section 4 general rate case in Docket No. RP95–408–000, et al. Columbia filed to have rates effective September 1, 1995, but the Commission, by letter order dated August 31, 1995, suspended rates for five months making the effective date February 1, 1996. Columbia subsequently filed, on December 29, 1995, tariff sheets to ''track'' when it filed its scheduled quarterly PGA and storage tracker filing on January 3, 1996.

Furthermore, ESNG states it has not billed its storage customers and will not until it receives the Commission's authorization as requested herein.

ESNG states that copies of the filing have been served upon its jurisdictional customers and interested State Commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rule 211 and Rule 214 of the Commission's Rules of Practice and Procedure (18 CFR Section 385.211 and Section 385.214). All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11679 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TM96–10–23–000]

Eastern Shore Natural Gas Company; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, Eastern Shore Natural Gas Company (ESNG) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1, certain revised tariff sheets in the above captioned docket, with proposed effective dates of April 1, 1996 and May 1, 1996, respectively.

ESNG states that the purpose of the instant filing is to track rate changes attributable to (a) storage service purchased from Transcontinental Gas Pipe Line (Transco) under Transco's Rate Schedules GSS and LSS the costs of which are included in the rates and charges payable under ESNG's Rate Schedules GSS and LSS effective beginning April 1, 1996 and (b) storage service purchased from Columbia Gas Transmission (Columbia) under Columbia's Rate Schedules SST and FSS the costs of which are included in the rates and charges payable under ESNG's Rate Schedules CWS and CFSS effective April 1, 1996 and May 1, 1996. This tracking filing is being made pursuant to Section 24 of the General Terms and Conditions of ESNG's FERC Gas Tariff to reflect changes in ESNG's jurisdictional rates.

ESNG states that copies of the filing have been served upon its jurisdictional customers and interested State Commissions.

Any person desiring to be heard or to protest this filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR Sections 325.211 and 325.214). All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party

must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11680 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. GT96–61–000]

El Paso Natural Gas Company; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, El Paso Natural Gas Company (El Paso), tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1–A, the following tariff sheets, to become effective June 1, 1996.

Third Revised Sheet No. 1
Second Revised Sheet No. 500

El Paso states that tendered tariff sheets proposed to become effective June 1, 1996, revise the Index of Customers contained in Volume No. 1–A to comply with Section 154.111 of the Commission's Regulations. El Paso proposes to remove the Index of Customers in its Volume No. 1–A Tariff, since it is has posted an Index of Customers on its electronic bulletin board, pursuant to Section 286.106(c) of the Commission's Regulations.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Sections 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11681 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. CP96–397–000]

Equitrans, L.P.; Notice of Application

May 6, 1996.

Take notice that on May 1, 1996, Equitrans, L.P. (Equitrans), 3500 Park Lane, Pittsburgh, Pennsylvania 15275, filed in Docket No. CP96–397–000 an application pursuant to Section 7(b) of the Natural Gas Act for permission and approval to abandon an exchange service with Columbia Gas Transmission Corporation (Columbia), all as more fully set forth in the application on file with the Commission and open to public inspection.

Equitrans proposes to abandon an exchange service with Columbia under its Rate Schedule X–99 which provided for the exchange in Upshur and Wetzel Counties, West Virginia.

Any person desiring to be heard or to make any protest with reference to said application should on or before May 28, 1996, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no motion to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that permission and approval for the proposed abandonment are required by the public convenience and necessity. If a motion for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Equitrans to appear or be represented at the hearing.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11682 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Project No. 10873–002 North Carolina]

Fall Line Hydro Company, Inc.; Notice of Withdrawal of Application for License

May 6, 1996.

Take notice that the Fall Line Hydro Company, Inc., applicant for the Cullasaja River Project No. 10873, located on the Cullasaja River, Macon County, North Carolina, has requested that its application for license be withdrawn. The applicant states that the project would be uneconomical due to the uncertainty that deregulation of the electrical utility industry has created.

The applicant filed the request on April 22, 1996, and the withdrawal of the license application for Project No. 10873 will become effective 15 days after the filing date of the request for withdrawal, unless that day is a Saturday, Sunday or holiday, in which case the application shall remain pending through the first business day following that day. New applications involving this project site, to the extent provided for under 18 CFR Part 4, may be filed on the next business day.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11683 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–230–000]

Florida Gas Transmission Company; Notice of Transition Cost Recovery Report

May 6, 1996.

Take notice that on May 2, 1996, Florida Gas Transmission Company (FGT) tendered for filing a Transition Cost Recovery Report pursuant to Section 24 of the General Terms and Conditions of its FERC Gas Tariff, Third Revised Volume No. 1.

FGT states that the Transition Cost Recovery Report filed summarizes the activity which has occurred in its TCR Account and Order 636 Account through April, 1996 and includes $4,171,777.79 of recoverable 636 transition costs not previously reported. Because the currently effective TCR and 636 reservation charge and TCR usage surcharge rates are at the maximum levels permitted by FGT's tariff, no tariff

revisions are required as a result of this filing.

FGT states that copies of the report were mailed to all customers serviced under the rate schedules affected by the report and the interested state commissions.

Any person desiring to be heard or to protest this filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 in accordance with sections 385.211 and 385.214 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11684 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. CP96–369–000]

Florida Gas Transmission Company; Notice of Application

May 6, 1996.

Take notice that on April 30, 1996, Florida Gas Transmission Company (Florida Gas), 1400 Smith Street, Houston, Texas 77002, filed in Docket No. CP96–369–000, an application pursuant to Section 7(b) of the Natural Gas Act and Part 157 of the Commission's Regulations. Florida Gas seeks an order authorizing the abandonment of its transportation service with Washington Gas Company (Washington Gas), known as Rate Schedule X–7. Florida Gas's request is more fully set forth in the application, which is on file with the Commission and open to public inspection.

Florida Gas says that in letter agreement dated December 17, 1984, it and Washington Gas have agreed to terminate the transportation service effective December 31, 1984. The transportation service had been rendered by Florida Gas under a transportation service agreement dated June 24, 1975, see Docket No. CP76–71, 56 FPC 463 (1976). This service agreement was designated as Rate Schedule X–7 in Florida Gas's Original Volume No. 3 of its FERC Gas Tariff. Florida Gas says that the proposed abandonment will not result in the abandonment of facilities nor will it result in the abandonment of service to any other customers of Florida Gas.

Any person desiring to be heard or to make any protest with reference to said application should on or before May 24, 1996, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no motion to intervene is filed within the time required herein, or if the Commission on its own review of the matter finds that permission and approval for the proposed abandonment are required by the public convenience and necessity. If a motion for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Florida Gas to appear or be represented at the hearing.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11685 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–229–000]

Koch Gateway Pipeline Company; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 2, 1996, Koch Gateway Pipeline Company (Koch) tendered for filing as part of its FERC Gas Tariff, Fifth Revised Volume No. 1, the following tariff sheets to be effective June 1, 1996:

Title Page
Fourth Revised Sheet No. 1
Third Revised Sheet No. 1412
First Revised Sheet No. 1704
First Revised Sheet No. 1705
Second Revised Sheet No. 1706
First Revised Sheet No. 1709
Second Revised Sheet No. 1710
Second Revised Sheet No. 1907
Fourth Revised Sheet No. 2705
Second Revised Sheet No. 2707
Fourth Revised Sheet No. 2706
First Revised Sheet No. 3300
First Revised Sheet No. 4010

Koch states that the above listed tariff sheets are being filed to bring Koch's tariff in compliance with Order No. 582. The tariff modifications include a statement with respect to Koch's order of discounts, information about reports required by the Commission, and other minor modifications such as deletion of cites to the Commission's regulations where these cites are now different as a result of Order No. 582.

Koch also states that the revised tariff sheets are being served upon all its customers, State Commissions, and other interested parties.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426, in accordance with Sections 385.214 and 385.211 of the Commission's regulations. All such motions or protests must be filed as provided in section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a Motion to Intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11686 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–228–000]

Mobile Bay Pipeline Company; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice than on May 2, 1996, Mobile Bay Pipeline Company (MBPC) tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, the following tariff sheets to be effective June 1, 1996:

Title Page

Third Revised Sheet No. 4
First Revised Sheet No. 23
First Revised Sheet No. 49
First Revised Sheet No. 129
First Revised Sheet No. 184
First Revised Sheet No. 272

MBPC states that the tariff sheets listed above are being filed to bring MBPC's tariff in compliance with the Order No. 582. MBPC also states that the tariff modifications include MBPC's conversion to thermal rather than volumetric units, a tariff statement describing its lateral line policy, and revising the cites to the Commission's regulations where these cites are now different as a result of Order No. 582.

MBPC also states that the revised tariff sheets are being served upon all its customers, State Commissions, and other interested parties.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426, in accordance with Sections 385.214 and 385.211 of the Commission's regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a Motion to Intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11688 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket Nos. RP95–326–009 and RP95–242–009]

Natural Gas Pipeline Company of America; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, Natural Gas Pipeline Company of America (Natural) tendered for filing proposed changes in its FERC Gas Tariff, Sixth Revised Volume No. 1 and Second Revised Volume No. 2, to become effective June 1, 1996.

Natural states that the purpose of this filing is to remove from its rates the cost of service effect of $8,468,644 of deferred take-or-pay costs. Such costs will be fully amortized by May 31, 1996, pursuant to the settlement approved July 25, 1991 in Docket Nos. RP91–22–000, *et al.*

Natural requests waiver of the Commission's Regulations to the extent necessary to permit the tariff sheets submitted to become effective June 1, 1996.

Natural states that copies of the filing are being mailed to all parties on the restricted service list in the referenced dockets.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Section 385.211 of the Commission's Rules and Regulations. All such protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestant parties to the proceeding. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11689 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–225–000]

Natural Gas Pipeline Company of America; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, Natural Gas Pipeline Company of America (Natural) tendered for filing as part of its FERC Gas Tariff, Sixth Revised Volume No. 1, Sixth Revised Sheet No. 22, to be effective June 1, 1996.

Natural states that the filing is submitted pursuant to Section 21 of the General Terms and Conditions of Natural's FERC Gas Tariff, Sixth Revised Volume No. 1 (Section 21), as the sixth semiannual limited rate filing under Section 4 of the Natural Gas Act and the Rules and Regulations of the Federal Energy Regulatory Commission (Commission) promulgated thereunder. The rate adjustments filed for are designed to recover Account No. 858 stranded costs incurred by Natural under contracts for transportation capacity on other pipelines. Costs for any Account No. 858 contracts specifically excluded under Section 21 are not reflected in this filing.

Natural requested specific waivers of Section 21 and the Commission's Regulations, including the requirements of Section 154.63, to the extent necessary to permit the tariff sheet to become effective June 1, 1996.

Natural states that copies of the filing are being mailed to Natural's jurisdictional customers and interested state regulatory agencies.

Any person desiring to be heard or to protest said filing should file a motion to intervene or a protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Sections 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the public reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11690 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–45–003]

Northern Border Pipeline Company; Notice of Compliance Filing

May 6, 1996.

Take notice that on May 2, 1996, Northern Border Pipeline Company (Northern Border) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1, the following tariff sheets, to become effective June 1, 1996:

Substitute Second Revised Sheet No. 108
Substitute Second Revised Sheet No. 117

Northern Border asserts that the purpose of this filing is to comply with the Commission's order issued December 29, 1995, in Docket No. RP96–45–000. On November 16, 1995, Northern Border filed proposed tariff sheets, pursuant to Natural Gas Act, Section 4, in Docket No. RP96–45–000 and reserved the right to file a later motion to place the proposed tariff sheets into effect at the end of a suspension period ordered by the Commission. On December 29, 1995, the Commission issued an order in Docket No. RP96–45–000 accepting and suspending certain filed tariff sheets for the maximum allowable period of five months to take effect, subject to refund, on June 1, 1996. Northern Border Pipeline Company, 73 FERC ¶ 61,399 (1995).

Accordingly, with this filing Northern Border moves to effectuate the tariff sheets accepted by the Commission in its December 29, 1995 order.

Northern states that copies of this filing have been served upon all parties in this proceeding and upon all of Northern Border's contracted shippers and affected state commissions.

Any person desiring to protest this filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Section 385.211 of the Commission's Rules and Regulations. All such protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Copies of this filing are on file with the Commission and available for public inspection in the Public Reference Room.

Linwood A. Watson,

Acting Secretary.

[FR Doc. 96–11691 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–223–000]

Panhandle Eastern Pipe Line Company; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, Panhandle Eastern Pipe Line Company (Panhandle) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1, the tariff sheets listed on Appendix A attached to the filing, proposed to be effective June 1, 1996.

Panhandle asserts that the purpose of this filing is to reinstate the Take-or-Pay Volumetric Surcharge pursuant to Section 18.10(g) of the General Terms and Conditions of Panhandle's tariff.

Panhandle states that the purpose of this filing is to establish a 0.10¢ per Dt. Reconciliation Amount Recovery Period volumetric surcharge in accordance with the provisions of section 18.10(g) of Panhandle's FERC Gas Tariff, First Revised Volume No. 1, to become effective June 1, 1996.

Panhandle states that a copy of this filing is being served on all affected customers and applicable state regulatory agencies.

Any person desiring to be heard or to protest this filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Sections 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Lindwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11692 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–224–000]

Panhandle Eastern Pipe Line Company; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, Panhandle Eastern Pipe Line Company (Panhandle) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1, the tariff sheets listed on Appendix A attached to the filing, proposed to be effective June 1, 1996.

Panhandle states that the purpose of this filing is to provide Panhandle's firm shippers under Rate Schedules FT, EFT and LFT with a customized reservation rate that will allow them maximum flexibility in dealing with market conditions throughout the contract year. The Customized Reservation Pattern (CRP) election will allow a firm shipper to shift, during each twelve month period commencing November 1, up to 80% of the reservation charge obligation for the April to October period into the preceding November to March period. By permitting a shipper to customize its cost-based reservation charges, CRP will raise or lower the maximum monthly charge to better reflect conditions in its own markets and to the secondary market for capacity release. This will further the Commission's goals of allocating capacity to those shippers who value it most and permit shippers to contract for services at rates which are designed to market gas and services competitively.

Panhandle states that a copy of this filing are being served on all affected customers and applicable state regulatory agencies.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Sections 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11693 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. DI96–5–000]

Rochester Gas and Electric Corp.; Notice Granting Extension of Time

May 6, 1996.

On March 4, 1996, the Commission issued a notice of the Petition for Declaratory Order filed by Rochester Gas and Electric Corporation for its Station 160 Hydroelectric Project located on the Genesee River in Livingston County, New York. The notice established April 22, 1996, as the deadline for filing comments in the proceeding.[1] A motion for an extension of time to file comments has been filed by Rochester Gas and Electric Corporation. For good cause shown, the April 22, 1996 deadline for filing comments in this proceeding is extended until May 20, 1996.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11722 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. EC96–21–000]

SEMASS Partnership; Notice of Filing

May 6, 1996.

Take notice that on April 30, 1996, SEMASS Partnership (SEMASS) filed an application seeking authorization under Section 203 of the Federal Power Act to transfer control of jurisdictional facilities in connection with the proposed sale by certain partners of SEMASS of eighty percent (80%) of the partnership interests in SEMASS to American Ref-Fuel Company of SEMASS, L.P.

[1] 61 FR 10576, Mar. 14, 1996.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 18 CFR 385.214). All such motions or protests should be filed on or before May 15, 1996. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11694 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP89–224–016]

Southern Natural Gas Company; Notice of Proposed Changes to FERC Gas Tariff

May 6, 1996.

Take notice that on April 30, 1996, Southern Natural Gas Company (Southern) tendered for filing as part of its FERC Gas Tariff, Seventh Revised Volume No. 1, the following tariff sheets to become effective May 1, 1996:

Fourth Revised Sheet No. 2
Third Revised Sheet No. 37
First Revised Sheet No. 39
Original Sheet No. 39a
First Revised Sheet No. 48
Second Revised Sheet No. 51
Original Sheet No. 51a
Third Revised Sheet No. 124
First Revised Sheet No. 127
Original Sheet No. 127a
First Revised Sheet No. 130
Original Sheet No. 130a
Original Sheet No. 212e–212g
First Revised Sheet No. 297
Original Sheet No. 297a
First Revised Sheet No. 315
Original Sheet No. 315a

Southern states that the purpose of this filing is to implement Tariff revisions proposed by Southern in its Stipulation and Agreement filed on March 15, 1995, in Docket Nos. RP89–224, et al., and approved by the Commission in its order issued on September 29, 1995.

Under the Stipulation and Agreement, Southern is required to implement these provisions on the first day of the month after the Commission issues an order on rehearing in Docket Nos. RP89–224, et al. On April 11, 1996, the Commission issued the final order on rehearing.

Any person desiring to protest this filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rule 211 of the Commission's Rules of Practice and Procedures (18 CFR Section 385.211). All such protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11695 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–227–000]

Tennessee Gas Pipeline Company; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, Tennessee Gas Pipeline Company (Tennessee) tendered for filing as part of its FERC Gas Tariff, Fifth Revised Volume No. 1, the following tariff sheet, with a proposed effective date of June 1, 1996:

First Revised Sheet No. 654

Tennessee states that the filing is intended to revise the pro forma Blanket Authorization Agreement in Tennessee's tariff to add a space for inserting the Blanket Agent's billing address.

Tennessee states that a copy of the filing has been served upon each of Tennessee's jurisdictional customers and all affected state commissions.

Any person desiring to be heard or to protest this filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 in accordance with 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11696 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–181–001]

Trunkline Gas Company; Notice of Compliance Filing

May 6, 1996.

Take notice that on May 1, 1996, Trunkline Gas Company (Trunkline) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1, the following tariff sheets, proposed to be effective April 20, 1996:

Sub Original Sheet No. 34B
Sub Original Sheet No. 45B
Sub Original Sheet No. 51B

Trunkline states that the purpose of this filing is to comply with Ordering Paragraph (B) of the Commission's April 19, 1996, Order in Docket No. RP96–181–000 to limit the applicability of the CRP mechanism to the primary market.

Trunkline states that a copy of this filing is being served on all affected customers, applicable state regulatory agencies and parties to this proceeding.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Section 385.211 of the Commission's Rules and Regulations. All such protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11697 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. OR96–13–000]

Ultramar Inc. v. Gaviota Terminal Company; Notice of Complaint

May 6, 1996.

Take notice that on April 30, 1996, Ultramar Inc. (Ultramar) filed a complaint pursuant to Sections 9, 13(1), and 15(1) of the Interstate Commerce Act (ICA), Section 1803 of the Energy Policy Act of 1992, and Rule 206 of the

Commission's Rules of Practice and Procedure against Gaviota terminal Company (Gaviota).

Ultramar alleges that Gaviota has (1) collected transportation charges before February 1, 1994, without filing a tariff with the Commission, (2) that the rates Gaviota collected thereafter were unjust, unreasonable, and discriminatory, and (3) that rates Gaviota collected since September 1, 1995, were in excess of the applicable indexed ceiling rates under Order Nos. 561 and 561–A without an adequate showing that such rates are justified by a substantial divergence between actual costs and the index ceiling. Ultramar seeks the refund of all unlawful charges collected by Gaviota and the establishment of lawful rates which are just, reasonable and non-discriminatory. This includes all funds in excess of variable and operating costs for the period for which no tariffs were filed.

Any person desiring to be heard or to protest the instant complaint should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 214 and 211 of the Commission's Rules of Practice and Procedure. All such motions or protests should be filed on or before May 30, 1996. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. Answers to this complaint shall be due on or before May 30, 1996.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11698 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TM96–3–119–000]

Young Gas Storage Company, Ltd.; Notice of Filing

May 6, 1996.

Take notice that on May 1, 1996, Young Gas Storage Company, Ltd. (Young) tendered for filing as part of its FERC Gas Tariff, Original Volume No. 1, the following tariff sheet, with a proposed effective date of June 1, 1996:

Fourth Revised Sheet No. 5

Young states that the purpose of its filing is to reflect an increase in the fuel reimbursement percentage based on actual experience and a two estimate from 2.0% to 2.6% effective June 1, 1996.

Young states that copies of this filing have been served on Young's jurisdictional customers and public bodies.

Any person desiring to be heard or to protest said filing should file a motion to intervene or a protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Sections 385.211 and 385.214 of the Commission's Rules of Practice and Procedure (18 CFR Sections 385.214 and 385.211). All such petitions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11699 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. RP96–226–000]

Young Storage Company, Ltd.; Notice of Proposed Changes in FERC Gas Tariff

May 6, 1996.

Take notice that on May 1, 1996, Young Storage Company, Ltd. (Young), tendered for filing as part of its FERC Gas Tariff, Original Volume No. 1, revised tariff sheets included as Appendix 1 to the filing, to be effective June 1, 1996.

Young states that the purpose of the filing is to comply with Commission Order No. 582 issued September 28, 1995 in Docket No. RM95–3–000. Order No. 582 requires a pipeline that is on a volumetric basis to convert to a thermal basis within one year of implementation. Young states that it is therefore converting its existing volumetric tariff to a thermal tariff using a conversion factor of 1077 Btu for each Mcf. Young states that there will be no change in revenues under the proposed revisions.

Young requests any waiver necessary of the Commission's Regulations to the extent necessary to permit the tariff sheets to become effective June 1, 1996, the start of the injection season.

Young states that copies of the filing are being mailed to all holders of its tariff.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rule 211 and Rule 214 of the Commission's Rules of Practice and Procedure (18 CFR Section 385.211 and Section 385.214). All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11700 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. EC96–20–000, et al.]

Hermiston Generating Company, L.P., et al.; Electric Rate and Corporate Regulation Filings

May 3, 1996.

Take notice that the following filings have been made with the Commission.

1. Hermiston Generating Company, L.P.

[Docket No. EC96–20–000]

Take notice that on April 26, 1996, Hermiston Generating Company, L.P. (Hermiston), tendered for filing an application for approval of the sale of certain described public utility facilities pursuant to an Option Agreement between Hermiston and PacifiCorp related to the acquisition by PacifiCorp of a fifty percent undivided interest in a 474 MW electric and steam generating plant, and other assets, located in Hermiston, Oregon. Hermiston has further requested confirmation that there is no need for the Commission to re-examine Hermiston's rates as a result of the proposed ownership changes. Hermiston has requested that the Commission act on an expedited basis.

Comment date: May 20, 1996, in accordance with Standard Paragraph E at the end of this notice.

2. Central Hudson Gas and Electric Corporation

[Docket No. ER96–1658–000]

Take notice that on April 26, 1996, Central Hudson Gas and Electric Corporation (CHG&E), tendered for filing pursuant to § 35.12 of the Federal Energy Regulatory Commission's

(Commission) Regulations in 18 CFR, a Service Agreement between CHG&E and NorAm Energy Services. The terms and conditions of service under this Agreement are made pursuant to CHG&E's FERC Electric Rate Schedule, Original Volume 1 (Power Sales Tariff) accepted by the Commission in Docket No. ER94–1662. CHG&E also has requested waiver of the 60-day notice provision pursuant to 18 CFR 35.11.

A copy of this filing has been served on the Public Service Commission of the State of New York.

Comment date: May 17, 1996, in accordance with Standard Paragraph E at the end of this notice.

3. Virginia Electric and Power Company

[Docket No. ER96–1659–000]

Take notice that on April 26, 1996, Virginia Electric and Power Company (Virginia Power), tendered for filing a Service Agreement between Cleveland Electric Illuminating Company and Virginia Power, dated February 21, 1996, under the Power Sales Tariff to Eligible Purchasers dated May 27, 1994. Under the tendered Service Agreement Virginia Power agrees to provide services to Cleveland Electric Illuminating Company under the rates, terms and conditions of the Power Sales Tariff as agreed by the parties pursuant to the terms of the applicable Service Schedules included in the Power Sales Tariff.

Copies of the filing were served upon the Virginia State Corporation Commission, the North Carolina Utilities Commission, and the Ohio Public Utilities Committee.

Comment date: May 17, 1996, in accordance with Standard Paragraph E at the end of this notice.

4. Virginia Electric and Power Company

[Docket No. ER96–1660–000]

Take notice that on April 26, 1996, Virginia Electric and Power Company (Virginia Power), tendered for filing a Service Agreement between Toledo Edison Company and Virginia Power, dated February 21, 1996, under the Power Sales Tariff to Eligible Purchasers dated May 27, 1994. Under the tendered Service Agreement Virginia Power agrees to provide services to Toledo Edison Company under the rates, terms and conditions of the Power Sales Tariff as agreed by the parties pursuant to the terms of the applicable Service Schedules included in the Power Sales Tariff.

Copies of the filing were served upon the Virginia State Corporation Commission, the North Carolina Utilities Commission, and the Ohio Public Utilities Commission.

Comment date: May 17, 1996, in accordance with Standard Paragraph E at the end of this notice.

5. Atlantic City Electric Company

[Docket No. ER96–1661–000]

Take notice that on April 26, 1996, Atlantic City Electric Company (ACE), tendered for filing an Agreement for Import Capability Transactions between ACE and Pennsylvania Power and Light Company. ACE requests that the Agreement be accepted to become effective April 27, 1996.

Copies of the filing were served on the New Jersey Board of Regulatory Commissioners.

Comment date: May 17, 1996, in accordance with Standard Paragraph E at the end of this notice.

6. Industrial Energy Applications, Inc.

[Docket No. ER96–1662–000]

Take notice that on April 26, 1996, Industrial Energy Applications, Inc. (IEA) submitted for filing a letter of acceptance from the Western Systems Power Pool (WSPP) indicating that IEA had been conditionally accepted for membership in WSPP. IEA requests that the Commission amend the WSPP Agreement to include IEA as a member.

IEA requests an effective date of May 1, 1996, for the proposed amendment and requests waiver or the Commission's notice requirements for good cause shown.

Copies of the filing were served upon counsel for WSPP and upon the WSPP Executive Committee.

Comment date: May 17, 1996, in accordance with Standard Paragraph E at the end of this notice.

7. MidAmerican Energy Company

[Docket No. ER96–1664–000]

Take notice that on April 29, 1996, MidAmerican Energy Company (MidAmerican), 106 East Second Street, Davenport, Iowa 52801, filed with the Commission a Report of Transactions under Rate Schedule For Power Sales (FERC Electric Tariff, Original Volume No. 5) for the Reporting Period of April 1, 1996 to April 15, 1996. This Report summarizes the rates and other terms of transactions with Purchasers who have entered into Service Agreements with MidAmerican under the Tariff or are eligible to purchase under the Tariff pursuant to interchange agreements with MidAmerican.

The Report of Transactions summarizes transactions which have been conducted within the 30 days prior to the filing pursuant to a previously filed service agreement or interchange agreement. Therefore, this filing is made within the 30-day period allowed by the Commission in *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139 (1993), *reh'g*, 65 FERC ¶ 61,081 (October 19, 1993).

Comment date: May 17, 1996, in accordance with Standard Paragraph E at the end of this notice.

8. MidAmerican Energy Company

[Docket No. ER96–1665–000]

Take notice that on April 29, 1996, MidAmerican Energy Company (MidAmerican), 106 East Second Street, Davenport, Iowa 52801, filed with the Commission Service Agreements with Tennessee Power Company (Tennessee Power) dated April 22, 1996, and Jpower Inc. (Jpower) dated April 22, 1996, entered into pursuant to MidAmerican's Rate Schedule for Power Sales, FERC Electric Tariff, Original Volume No. 5.

MidAmerican requests an effective date of April 22, 1996, for the Agreement with Tennessee Power and April 22, 1996 for the Agreement with Jpower, and accordingly seeks a waiver of the Commission's notice requirement. MidAmerican has served a copy of the filing on Tennessee Power, JPower, the Iowa Utilities Board, the Illinois Commerce Commission and the South Dakota Public Utilities Commission.

Comment date: May 17, 1996, in accordance with Standard Paragraph E at the end of this notice.

Standard Paragraph

E. Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 18 CFR 385.214). All such motions or protests should be filed on or before the comment date. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11674 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–P

Notice of Environmental Compliance and Applicant Environmental Report Preparation Training Courses

May 6, 1996.

The Office of Pipeline Regulation (OPR) staff is conducting three sessions of its environmental compliance training course and the course on preparing the applicant's environmental report.

These courses are a result of the positive response to our outreach training courses held from 1992 through 1995. We encourage interested organizations and the public to take advantage of the courses to gain an understanding of the requirements and objectives of the Commission in ensuring compliance with all environmental certificate conditions and meeting its responsibilities under the National Environmental Policy Act and other laws and regulations.

Environmental Report Preparation Course

The environmental report preparation course presentation and the manual focus primarily on Section 7 filings. However, the course manual will address the following topics:

A. What types of projects require environmental filings.
   1. Natural Gas Act section 7
   2. Natural Gas Policy Act filings
   3. Section 2.55 replacements
B. What filings are required of each type of filing.
C. What to include in each filing.
D. Potential time saving procedures.
   1. Applicant-prepared DEA
   2. Third-party EA or EIS

The staff intends the manual to be a cookbook for preparing environmental filings under section 7 of the Natural Gas Act.

If you have specific questions related to the subject matter of this course, or if you would like the course to address a particular item, please call Mr. John Leiss at (202) 208–1106.

The one-day environmental report preparation course will be held on the dates and at the locations shown below. Attendees must call the numbers listed for the hotels by the reservation deadline and identify themselves as FERC seminar attendees to receive the discounted group rate. Hotel information for Houston and Denver will be available after May 15 through the telephone number given below under Preregistration.

Session and Location: June 25, Dupont Plaza Hotel, 1500 New Hampshire Avenue, NW., Washington, DC 20036, (202) 483–6000; July 30, Houston; August 13, Denver.

Hotel Reservation Deadline: June 10.

Environmental Compliance Training Course

The two-day environmental compliance training course will include the following topics:

A. Postcertificate clearance filings;
B. Environmental inspection as it relates to:
   1. Right-of-way preparation;
   2. Temporary erosion control;
   3. Cultural resources/Paleontology;
   4. Waterbody crossings;
   5. Wetland construction;
   6. Residential area construction;
   7. Right-of-way restoration; and
   8. techniques for environmental compliance.

The environmental compliance training course will be held on the dates and at the locations shown below. Attendees must call the numbers listed for the hotels by the reservation deadline and identify themselves as FERC seminar attendees to receive the discounted group rate. Hotel information for Houston and Denver will be available after May 15 through the telephone number given below under Preregistration.

Session and Location: June 26–27, Dupont Plaza Hotel, 1500 New Hampshire Avenue, NW., Washington, DC 20036, (202) 483–6000; July 31–August/1, Houston; August 14–15, Denver.

Hotel Reservation Deadline: June 10.

Preregistration

The OPR staff and Foster Wheeler Environmental Corporation, the Commission's environmental support contractor for natural gas projects, will conduct the training. There is no fee for the courses, but you must preregister because space is limited.

If you would like to attend either of these courses, please call the telephone number listed below to obtain a preregistration form.[1] Note: If you plan to attend both the environmental report preparation session and the subsequent environmental compliance training session, you must preregister separately for each (only one form is needed). Attendance will be limited to the first 150 people to preregister in each course. Call or FAX requests for preregistration forms to: Ms. Sarah Adam, Foster Wheeler Environmental Corporation, 470 Atlantic Avenue, Boston, MA 02210, Telephone: (617) 542–8805, FAX: (617) 695–1587.

You will receive confirmation of preregistration and additional information before the training course(s).

Additional training will be offered in the future. Please indicate whether you would like these courses to be offered again, or if you are interested in any other courses with different topics or audiences. Please indicate your preferences for location and time of year. Suggestions on format are welcome.

Linwood A. Watson, Jr.,

Acting Secretary.

BILLING CODE 6717–01–M

[1] The preregistration forms referenced in this notice are not being printed in the Federal Register. Copies of the forms were sent to those receiving this notice in the mail.

Preregistration Form for the Federal Energy Regulatory Commission's Natural Gas Pipeline Environmental Compliance Training and Environmental Report Preparation Courses

WASHINGTON, D.C., JUNE 25-27, 1996

Contact Name:_____

Position/Title:_____

Affiliation:_____

Mailing Address:_____

_____

Phone Number:_____ **FAX Number:**_____

Please note: You must preregister for *each* course you wish to attend.

I would like to preregister the following people for the ***1-day Environmental Report Preparation Course*** on JUNE 25, 1996, in WASHINGTON, D.C. (PLEASE PRINT NAMES NEATLY):

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

Attach separate sheet if necessary.

I would like to preregister the following people for the ***2-day Environmental Compliance Training Course*** on JUNE 26 - 27, 1996, in WASHINGTON, D.C. (PLEASE PRINT NAMES NEATLY):

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

Attach separate sheet if necessary.

RETURN TO:
Sarah Adam
Foster Wheeler Environmental Corporation
470 Atlantic Avenue
Boston, MA 02210
FAX: (617) 695-1587
Office:(617) 542-8805 or (617) 451-9942

Preregistration Form for the Federal Energy Regulatory Commission's Natural Gas Pipeline Environmental Compliance Training and Environmental Report Preparation Courses

HOUSTON, JULY 30 - AUGUST 1, 1996

Contact Name:_____

Position/Title:_____

Affiliation:_____

Mailing Address:_____

_____

Phone Number:_____ **FAX Number:**_____

Please note: You must preregister for *each* course you wish to attend.

I would like to preregister the following people for the ***1-day Environmental Report Preparation Course*** on JULY 30, 1996, in HOUSTON (PLEASE PRINT NAMES NEATLY):

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

Attach separate sheet if necessary.

I would like to preregister the following people for the ***2-day Environmental Compliance Training Course*** on JULY 31 - AUGUST 1, 1996, in HOUSTON (PLEASE PRINT NAMES NEATLY):

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

Attach separate sheet if necessary.

RETURN TO:
Sarah Adam
Foster Wheeler Environmental Corporation
470 Atlantic Avenue
Boston, MA 02210
FAX: (617) 695-1587
Office:(617) 542-8805 or (617) 451-9942

Preregistration Form for the Federal Energy Regulatory Commission's Natural Gas Pipeline Environmental Compliance Training and Environmental Report Preparation Courses

DENVER, AUGUST 13 - 15, 1996

Contact Name:_____

Position/Title:_____

Affiliation:_____

Mailing Address:_____

_____

Phone Number:_____ **FAX Number:**_____

Please note: You must preregister for *each* course you wish to attend.

I would like to preregister the following people for the ***1-day Environmental Report Preparation Course*** on AUGUST 13, 1996, in DENVER (PLEASE PRINT NAMES NEATLY):

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

Attach separate sheet if necessary.

I would like to preregister the following people for the ***2-day Environmental Compliance Training Course*** on AUGUST 14 - 15, 1996, in DENVER (PLEASE PRINT NAMES NEATLY):

_____ _____ _____

_____ _____ _____

_____ _____ _____

_____ _____ _____

Attach separate sheet if necessary.

RETURN TO:
Sarah Adam
Foster Wheeler Environmental Corporation
470 Atlantic Avenue
Boston, MA 02210
FAX: (617) 695-1587
Office:(617) 542-8805 or (617) 451-9942

[FR Doc. 96–11701 Filed 5–9–96; 8:45 am]
BILLING CODE 6717–01–C

Notice of Revised Exhibit J

May 6, 1996.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Type of Application:* Revised Exhibit J.

b. *Project No.:* 2299–037.

c. *Date Filed:* October 30, 1995.

d. *Applicant:* Turlock Irrigation District.

e. *Name of Project:* Don Pedro Project.

f. *Location:* On Tuolumne River, La Grange City, Tuolumne County, California.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. Sec. 791(a)–825(r).

h. *Applicant Contact:* Mr. Paul D. Elias, General Manager, Turlock Irrigation District, P.O. Box 949, Turlock, CA 95381 (209) 883–8211.

i. *FERC Contact:* Anum Purchiaroni, (202) 219–3297.

j. *Comment Date:* June 24, 1996.

k. *Description of Project:* The licensee filed a revised exhibit J to reflect changes to two of the project's transmission lines; the East and West lines. Under the license, the East and West lines extended from the Don Pedro switchyard to Turlock Irrigation District's Geer Substation. In 1983, the licensee constructed a new substation (named Hawkins) between Don Pedro Project and Geer Substation. The licensee reconfigured the East line by constructing 2 miles of new line connecting it to the Hawkins Substation, and removed the West line from service. The total length of the East line is 23 miles, which is 8 miles shorter than authorized by the license. The new substation and reconfigured transmission line, which were constructed without prior Commission authorization, affected properties owned by the licensee.

1. This notice also consists of the following standard paragraphs: B, C2, and D2.

B. Comments, Protests, or Motions to Intervene—Anyone may submit comments, a protest, or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, .211, .214. In determining the appropriate action to take, the Commission will consider all protests or other comments filed, but only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any comments, protests, or motions to intervene must be received on or before the specified comment date for the particular application.

C2. Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS,'' ''RECOMMENDATIONS FOR TERMS AND CONDITIONS,'' ''NOTICE OF INTENT TO FILE COMPETING APPLICATION,'' ''COMPETING APPLICATION,'' ''PROTEST,'' or ''MOTION TO INTERVENE,'' as applicable, and the Project Number of the particular application to which the filing refers. Any of these documents must be filed by providing the original and the number of copies provided by the Commission's regulations to: The Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426. A copy of a notice of intent, competing application, or motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

D2. Agency Comments—Federal, state, and local agencies are invited to file comments on the described application. A copy of the application may be obtained by agencies directly from the Applicant. If an agency does not file comments within the time specified for filing comments, it will be presumed to have no comments. One copy of an agency's comments must also be sent to the Applicant's representatives.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 96–11675 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–M

ENVIRONMENTAL PROTECTION AGENCY

[FRL–5502–9]

Agency Information Collection Activities Up for Renewal

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this notice announces that the Information Collection Request (ICR) listed below is coming up for renewal. Before submitting the renewal package to the Office of Management and Budget (OMB), the Environmental Protection Agency (EPA or the Agency) is soliciting comments on specific aspects of the collection as described below.

DATES: Comments must be submitted on or before July 9, 1996.

ADDRESSES: Phaseout Manager, Stratospheric Protection Division, U.S. EPA (6205J), 401 M Street, S.W., Washington, D.C. 20460. Materials relevant to this proposed rulemaking are contained in Public Docket No. A–92–13. This docket is located in Room M–1500, Waterside Mall (Ground Floor), U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460. Dockets may be inspected from 8:30 a.m. to 5:30 p.m., Monday through Friday. A reasonable fee may be charged for copying docket materials.

FOR FURTHER INFORMATION CONTACT: Tom Land, Stratospheric Protection Division, U.S. EPA (6205J), 401 M Street, S.W., Washington, D.C. 20460, (202) 233–9185, phone: (202) 233–9185, fax: (202) 233–9637. For questions only, you may use the electronic address: land.tom@epamail.epa.gov. All comments must be sent to the docket.

SUPPLEMENTARY INFORMATION:

Affected entities: Entities affected by this action are companies that produce, import, export, transform, and destroy controlled ozone-depleting substances, as well as suppliers of laboratory ozone-depleting chemicals and companies deemed to have an essential use of these chemicals beyond the phaseout.

Title: ''Recordkeeping and Periodic Reporting of the Production, Import, Export, Recycling, Destruction, Transhipment and Feedstock Use of Ozone-depleting Substances.'' OMB Control Number: 2060–0170. EPA Control Number: 1617.06. Expiration Date: September 30, 1996.

Abstract: EPA accelerated the phaseout of controlled class I ozone-depleting substances under Section 606 of the Clean Air Act Amendments of 1990 (CAA) in regulations published on December 10, 1993, in the Federal Register (58 FR 65018) and codified in 40 CFR Subpart B (§ 82.1 *et seq.*) These regulations were amended in the Federal Register on May 10, 1995, (60 FR 24970) in order to ensure an orderly phaseout and account for exempted production and consumption. Under the Montreal Protocol and Title VI of the CAA, consumption is defined as production plus imports minus exports. The ICR renewal indicates changes in reporting requirements resulting from the phaseout. The reasons information is collected, the way information is used, and whether the requirements are mandatory, voluntary, or required to obtain a benefit, are described below. The ICR renewal will not include any burden for third-party or public disclosures not previously reviewed and approved by OMB.

EPA monitors production, import, export, transformation, destruction of controlled substances and special

exemptions beyond the phaseout of class I controlled substances through reporting requirements published in regulations. These reporting requirements are designed to:

(1) Satisfy U.S. obligations under the international treaty, the Montreal Protocol on Substances that Deplete the Ozone Layer;

(2) Fulfill statutory obligations under Section 603(b) of Title VI of the CAA;

(3) Report to Congress on the production, use and consumption of class I and class II controlled substances as statutorily required in Section 603(d) of the CAA;

(4) Address Federal and industry concerns regarding illegal imports of newly produced and previously used controlled substances that are undercutting U.S. markets.

The information submitted to EPA is maintained in a Tracking System that allows the Agency:

(1) to maintain control over total production and consumption of controlled substances to satisfy conditions of the CAA and fulfill U.S. obligations under the Protocol,

(2) to monitor compliance with limits and restrictions on production, imports, exports and specific exemptions to the phaseout for individual U.S. companies

(3) to enforce against illegal importers and other violations related to the control of class I and class II controlled substances.

The Montreal Protocol and Title VI of the CAA establish limits on total U.S. production, import and export of class I and class I controlled substances. As of January 1, 1996, the U.S. is obligated under the Protocol to cease production and import of class I controlled substances (except methyl bromide) with exemptions for essential-uses, transformation, destruction and previously used material. The Protocol also establishes a limit on total consumption of class II controlled substances beginning in 1996. The CAA has its own limits on production and consumption of controlled substances that EPA must enforce using the information submitted.

To ensure U.S. compliance with the limits and restrictions established by the Protocol and the CAA, the regulation establishes controls on individual companies. The limits and restrictions for individual U.S. companies are monitored by EPA through the reporting requirements established in the regulation. The information provided is entered into EPA's Stratospheric Protection Tracking System. The Tracking System allows EPA to conduct compliance monitoring for individual companies, as well as compliance monitoring for the U.S. with respect to Protocol obligations and statutory requirements under the CAA.

EPA uses the information to direct special attention to illegal activities associated with the import of both newly produced and previously used controlled substances. Illegal imports and the avoidance of the tax on these chemicals make them more available, reduce the incentive to shift to alternatives, and penalize companies who are complying with U.S. laws. EPA is an active part of the Federal inter-agency taskforce conducting nation-wide enforcement actions. The information provided to EPA in response to the accelerated phaseout regulations often form the basis for cases.

The regulation outlines both recordkeeping and reporting requirements. EPA has produced a new Guidance Document that explains the simplifications and changes in post-phaseout reporting and includes the revised forms. In conjunction with the new Guidance Document, EPA is developing a new industry electronic version of the reporting/tracking system for industry reporting. EPA is also initiating a review of all reporting requirements under the Montreal Protocol and plans on leading an international effort to simplify them to reduce U.S. burden and burden for reporting companies.

The EPA would like to solicit comments to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information;

(iii) Enhance the quality, utility, and clarity of the information to be collected; and

(iv) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are displayed in 40 CFR Part 9.

Burden Statement: The burden hours shown represent the hours in the information collection request (ICR) renewal. The renewal significantly reduces overall burden hours due to the transition to the post-phaseout period. The annual burden hours prior to the phaseout were estimated to be 34,110 hours. Today's ICR renewal estimates annual burden hours to be 10,532 hours.

The following is a Table summarizing the burden hours for compiling information and submitting it to EPA Headquarters:

Collection activity	Number of respondents	Responses/ respondent	Total re-sponses	Hours per response	Total hours
Producer's Report	8	4	32	16	512
Importer's Report	6	4	24	16	384
Notification of Trade	2	1	2	2	4
Export Report	10	1	10	120	1200
Lab Certification	1000	1	1000	1	1000
Class II Report	14	4	56	16	896
Transformation and Destruction	15	1	15	120	1800
Essential Use and	12	4	48	32	1536
Lab Suppliers	25	4	100	32	3200
Total burden hrs					10532

This estimate includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any

previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Send comments regarding these matters, or any other aspects of the information collection, including suggestions for reducing the burden, to the address listed above under **ADDRESS** near the top of this Notice.

Dated: April 30, 1996.

Paul M. Stolpman,

Director, Office of Atmospheric Programs.

[FR Doc. 96–11755 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

[FRL–5502–8]

Air Pollution Control; Proposed Actions on Clean Air Act Grants to the South Coast Air Quality Management District; California

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed determinations with request for comments and notice of opportunity for public hearing.

SUMMARY: The U.S. EPA has made two proposed determinations that reductions in expenditures of non-Federal funds for the South Coast Air Quality Management District (SCAQMD) in Diamond Bar, California are a result of non-selective reductions in expenditures. These determinations, when final, will permit the SCAQMD to keep the financial assistance awarded to it by EPA for FY–95, and to be awarded financial assistance for FY–96 by EPA, under section 105(c) of the Clean Air Act (CAA).

DATES: Comments and/or requests for a public hearing must be received by EPA at the address stated below by June 10, 1996.

ADDRESSES: All comments and/or requests for a public hearing should be mailed to: Douglas K. McDaniel, Air Grants Section (A–2–3), Air and Toxics Division, U.S. EPA Region IX, 75 Hawthorne Street, San Francisco, California 94105–3901; FAX (415) 744–1076.

FOR FURTHER INFORMATION CONTACT: Douglas K. McDaniel, Air Grants Section (A–2–3), Air and Toxics Division, U.S. EPA Region IX, 75 Hawthorne Street, San Francisco, California 94105–3901 at (415) 744–1246.

SUPPLEMENTARY INFORMATION: Under the authority of Section 105 of the CAA, EPA provides financial assistance (grants) to the SCAQMD, whose jurisdiction includes Los Angeles and Orange Counties in southern California, to aid in the operation of its air pollution control programs. In FY–95, EPA awarded the SCAQMD $7,454,238, which represented approximately 7.8% of the SCAQMD's budget.

Section 105(c)(1) of the CAA, 42 U.S.C. 7405(c)(1), provides that ''[n]o agency shall receive any grant under this section during any fiscal year when its expenditures of non-Federal funds for recurrent expenditures for air pollution control programs will be less than its expenditures were for such programs during the preceding fiscal year. In order for [EPA] to award grants under this section in a timely manner each fiscal year, [EPA] shall compare an agency's prospective expenditure level to that of its second preceding year.'' EPA may still award financial assistance to an agency not meeting this requirement, however, if EPA, ''after notice and opportunity for public hearing, determines that a reduction in expenditures is attributable to a non-selective reduction in the expenditures in the programs of all Executive branch agencies of the applicable unit of Government.'' CAA § 105(c)(2). These statutory requirements are repeated in EPA's implementing regulations at 40 CFR 35.210(a).

In its FY–95 § 105 application, which EPA reviewed in early 1995, the SCAQMD projected expenditures of non-Federal funds for recurrent expenditures (or its maintenance of effort (MOE)) of $82,811,585. This MOE would have been sufficient to meet the MOE requirements of the CAA, i.e. it would have been equal to or greater than the MOE for the previous year (FY–94). In January of 1996, however, the SCAQMD submitted to EPA final documentation which shows that its actual FY–95 MOE was $78,479,091. This amount represents a shortfall of $2,026,404 from the MOE of $80,505,495 for the preceding fiscal year (FY–94). In order for the SCAQMD to be eligible to keep its FY–95 grant, EPA must make a determination under § 105(c)(2).

Furthermore, in its FY–96 § 105 grant application the SCAQMD projected MOE of $78,452,571. This amount represents a shortfall of $26,520 from the actual FY–95 MOE of $78,479,091. In order for the SCAQMD to be eligible to be awarded its FY–96 grant, EPA must make a determination under § 105(c)(2).

The SCAQMD is a single-purpose agency whose primary source of funding is emission fee revenue. It is the ''unit of Government'' for § 105(c)(2) purposes. The SCAQMD submitted documentation to EPA which shows that over the last three years emission reductions brought on by a combination of economic recession and more restrictive emission rules have reduced fee revenues from stationary sources from a high of $74,433,331 in 1990–1991 to $52,282,026 in 1994–1995. The SCAQMD projects this revenue loss to continue through FY–96. As a result, the SCAQMD has instituted hiring/salary freezes, furloughs, and layoffs, has reduced its equipment purchases and contract expenditures, and has instituted new programs to reduce costs such as permit streamlining, computer-assisted permit processing, and privatization efforts.

Therefore, the SCAQMD's MOE reductions resulted from a loss of fee revenues due to circumstances beyond its control. EPA proposes to determine that the SCAQMD's lower FY–95 and FY–96 MOE levels meet the § 105(c)(2) criteria as resulting from a non-selective reduction of expenditures. Pursuant to 40 CFR 35.210, these determinations will allow the SCAQMD to keep the funds received from EPA for FY–95 and be awarded financial assistance for FY–96.

This notice constitutes a request for public comment and an opportunity for public hearing as required by the Clean Air Act. All written comments received by June 10, 1996 on this proposal will be considered. EPA will conduct a public hearing on this proposal only if a written request for such is received by EPA at the address above by June 10, 1996.

If no written request for a hearing is received, EPA will proceed to both final determinations. While notice of the final determinations will not be published in the Federal Register, copies of the determinations can be obtained by sending a written request to Douglas McDaniel at the above address.

Dated: May 2, 1996.

David P. Howekamp,

Director, Air and Toxics Division, U.S. EPA, Region 9.

[FR Doc. 96–11753 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

[FRL–5503–5]

Acid Rain Provisions

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: EPA today announces the allocation of allowances to small diesel

refineries for desulfurization of fuel during 1995. The eligibility for and calculation of allowances to small diesel refineries is in accordance with section 410(h) of the Clean Air Act, implemented at 40 CFR 73 subpart G.

FOR FURTHER INFORMATION CONTACT: Kenon Smith, EPA Acid Rain Division (6204J), 401 M St., SW, Washington DC; telephone (202) 233–9164.

SUPPLEMENTARY INFORMATION: EPA's Acid Rain Program was established by Title IV of the Clean Air Act Amendments of 1990 (CAAA) to reduce acid rain in the continental United States. The Acid Rain Program will achieve a 50 percent reduction in sulfur dioxide (SO_2) emissions from utility units. The SO_2 reduction program is a flexible market-based approach to environmental management. As part of this approach, EPA allocates ''allowances'' to affected utility units. Each allowance is a limited authorization to emit up to one ton of SO_2. At the end of each calendar year, each unit must hold allowances in an amount equal to or greater than its SO_2 emissions for the year. Allowances may be bought, sold, or transferred between utilities and other interested parties. Those utility units whose annual emissions are likely to exceed their allocations may install control technologies or switch to cleaner fuels to reduce SO_2 emissions or buy additional allowances.

Section 410(h) of the Clean Air Act provides allowances for small diesel refineries that desulfurize diesel fuel from October 1, 1993 through December 31, 1999. Small refineries are not otherwise affected by the Acid Rain Program and do not need the allowances to comply with any provision of the Clean Air Act. Thus, the allowances serve as a financial benefit to small diesel refineries desulfurizing diesel fuel.

The following table lists the allowances allocated to eligible small diesel refineries for desulfurization in 1995. A total of 29,411 allowances are allocated to 19 refiners. These allowances have a compliance year of 1996.

Refiner	Refinery name or location	Allocation
Big West Oil.	Flying J, Utah	1,277
Cenex	Laurel, Montana	1,500
Crysen	Woods Cross, Utah	806
Frontier	Cheyenne, Wyoming	1,500
Gary Williams.	Bloomfield*	867
Giant	Bloomfield*	271
	Ciniza, New Mexico	1,500
Holly	Lea, New Mexico	1,500
	Navajo, New Mexico	1,500
	Montana	358
Hunt	Tuscaloosa, Alabama	1,500
Kern	Bakersfield, California	1,500
La Gloria	Tyler, Texas	1,500
Lion	El Dorado, Arkansas	1,500
Paramount	Paramount,California	1,500
Pennzoil	Atlas	1,500
	Products	512
Powerine	Santa Fe Springs	1,479
Pride	Abilene, Texas	1,316
Sinclair	Little America, Wyoming.	1,439
	Sinclair, Wyoming	1,500
	Tulsa, Oklahoma	1,500
U.S. Oil & Refining.	Tacoma, Washington	932
Witco	Golden Bear, California.	101
Wyoming Refining.	New Castle, Wyoming	553

*Gary Williams sold the Bloomfield refinery to Giant on October 4, 1995. Gary Williams is allocated allowances for production through October 3 and Giant is credited with production from October 4 through December 31.

Requests for allowances for desulfurization during 1996 are due no later than April 1, 1997. Allowances allocated in 1997 will have a compliance year of 1997.

Dated: May 3, 1996.

Brian J. McLean,

Director, Acid Rain Division.

[FR Doc. 96–11752 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–P

[FRL–5503–1]

Establishment of Federal Advisory Committee

AGENCY: Environmental Protection Agency (EPA).

SUMMARY: Pursuant to the Federal Advisory Committee Act, 5 U.S.C., App. 2, the Office of Research and Development (ORD) at the U.S. Environmental Protection Agency (EPA) is establishing a Federal Advisory Committee (Board of Scientific Counselors) to provide expert scientific and engineering advice on the operation of its research program.

The primary functions of the Board of Scientific Counselors (BOSC) are to: Evaluate science and engineering research programs, laboratories, and research-management practices of ORD and recommend actions to improve their quality and/or strengthen their relevance to the mission of the EPA, and evaluate and provide advice concerning the utilization of peer review within ORD to sustain and enhance the quality of science in EPA.

Members of the BOSC will be appointed by the EPA's Deputy Administrator from a list of nominations supplied by the Assistant Administrator for Research and Development. ORD received nominations from its National Centers and Laboratories of highly qualified experts in the science and engineering community. The selected individuals recommended by the AA/ORD represent a cross-section of distinquished individuals with expertise in environmental science and technology. The Committee is necessary and in the public interest.

The first meeting of the BOSC will be in mid-June 1996.

FOR FURTHER INFORMATION CONTACT: Shirley R. Hamilton, Designated Federal Official, U.S. Environmental Protection Agency, Office of Research and Development, NCERQA (MC 8701), 401 M Street, SW, Washington, DC 20460, 202–260–0468.

Dated: April 30, 1996.

Robert J. Huggett,

Assistant Administrator for Research and Development.

[FR Doc. 96–11754 Filed 5– 9–96; 8:45 am]

BILLING CODE 6560–50–P

[OPPTS–00183; FRL–5362–5]

Grants to Develop and Carry Out Authorized State Accreditation and Certification Programs for Lead-Based Paint Professionals

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of funds availability; solicitation of applications for financial assistance.

SUMMARY: This notice announces EPA's intent to enter into cooperative agreements with states and territories and federally recognized Indian governing bodies which provide financial assistance for purposes of developing and carrying out authorized accreditation and certification programs for professionals engaged in lead-based paint activities pursuant to the Toxic Substances Control Act (TSCA), as amended by section 404(g) of the Residential Lead-Based Paint Hazard Reduction Act of 1992. The notice describes eligible activities, application procedures and requirements, and funding criteria. EPA anticipates that up to $12,500,000 will be available during federal fiscal year 1996 (FY96) for awards to eligible recipients. There are no matching share requirements for this assistance. This is the third year that funding is being made available for these grants. Subject to future budget

limitations, EPA plans to provide this support on a continuing multi-year or program basis. All cooperative agreements will be administered by the appropriate EPA regional office.

DATES: In order to be considered for funding during the FY96 award cycle, all applications must be received by the appropriate EPA regional office on or before June 10, 1996. EPA will make its award decisions and execute its FY96 cooperative agreements by September 30, 1996.

FOR FURTHER INFORMATION CONTACT: For general information, contact: Susan B. Hazen, Director, Environmental Assistance Division (7408), Office of Pollution Prevention and Toxics, Environmental Protection Agency, Rm E–543B, 401 M St., SW., Washington, DC 20460, (202) 554–1404, TDD: (202) 554–0551, e-mail: TSCA-Hotline@epamail.epa.gov. For technical information, contact the appropriate Regional Primary Lead Contact person listed in Unit V. of this notice.

SUPPLEMENTARY INFORMATION: TSCA section 404(g) authorizes EPA to award non-matching grants to states, territories, and federally-recognized Indian governing bodies to develop and carry out authorized programs for the training of individuals engaged in lead-based paint activities, the accreditation of training programs for these individuals, and the certification of contractors engaged in lead-based paint activities. To achieve authorization under Title IV of TSCA, programs must: (1) Be as protective of human health and the environment as the federal program established under TSCA section 402 or 406, or both, and (2) provide adequate enforcement. For states and territories that fail to obtain authorization within 2 years following promulgation of TSCA section 402 or 406 regulations, EPA must, by such date, administer and enforce a program for TSCA section 402 or 406.

Pursuant to Title IV of TSCA, EPA encourages states, territories, and federally-recognized Indian governing bodies to seek authorization of their own training, accreditation, and certification programs for lead-based paint activities. EPA therefore recommends that eligible parties seek funding through the TSCA section 404(g) assistance program, which is now being implemented to help achieve these ends. EPA further recommends that eligible parties plan to utilize this grant support in a way that complements any related financial assistance they may receive from other federal sources. EPA will, however, seek to ensure that all federally-funded lead activities are undertaken in a coordinated fashion.

EPA will work with prospective applicants to develop cooperative agreements which promote a variety of objectives deemed critical to the success of its national lead program. These include: (1) Permitting flexible approaches to reducing lead hazards, (2) developing a nationwide pool of qualified lead abatement professionals, (3) encouraging pollution prevention in lead-based paint activities, (4) promoting environmental justice in the reduction of lead exposures and the prevention of lead poisoning, (5) fostering the establishment of comprehensive and integrated lead management programs by states, territories and Indian governing bodies, and (6) promoting reciprocity among authorized programs in the training and certification of lead abatement professionals.

I. Eligibility

All states are eligible to apply for and receive assistance under section 404(g) of TSCA. The term ''state,'' for purposes of eligibility, refers broadly to any state of the United States, the District of Columbia, any federally-recognized Indian governing body, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, the Canal Zone, American Samoa, the Northern Mariana Islands, and any other territory or possession of the United States.

II. Authority

The ''TSCA Title IV State Lead Grants Program'' is a financial assistance program administered by EPA under authority of TSCA section 404(g). Each of EPA's 10 regional administrators will be delegated the authority to enter into cooperative agreements with eligible ''states.'' However, because EPA's authority to award 404(g) funding to Indian governing bodies is contingent upon final promulgation of the forthcoming regulations mandated under sections 402 and 404 of TSCA, EPA plans to award all funds to Indian governing bodies under authority of TSCA section 10(a) during this award cycle (FY96). Further, all references in this notice to Indian governing bodies being treated as states is contingent upon EPA's final promulgation of the regulations mandated under TSCA sections 402 and 404.

EPA recognizes that when TSCA Title IV was enacted on October 28, 1992, states had widely varying capabilities for addressing lead hazards. Individual states currently fall within one of three broad categories of program development: (1) States without lead programs, (2) states with programs that qualify for authorization that may need assistance in carrying out these programs, and (3) states with lead programs that will require modification before qualifying for authorization. Each state's need for assistance will vary, in part, according to the level of lead program development the state has attained. The type of program activity a given state seeks to pursue may also vary in a corresponding manner.

Although EPA generally supports all state activities aimed at developing or carrying out authorized state lead programs, the Agency does recognize certain priorities. Because few states presently have adequate lead program capabilities, as measured against TSCA sections 402 and 406, EPA's highest priority will be to support the development of new state programs. A second priority will be to support the continued implementation of authorized state programs. A third priority will be to support the implementation of existing state programs which do not presently qualify for authorization but which are otherwise willing to work toward timely authorization. Although these priorities do not constitute the Agency's criteria for award determinations, EPA will consider these items in its cooperative agreement negotiations with applicants.

EPA has established three general funding categories that reflect the different status, or levels, of state lead program development. They are not mutually exclusive, and it is permissible for a state's work plan to combine elements from two or more categories. Numerous examples of activities considered to be eligible for funding are described in a separate EPA publication entitled ''State and Tribal Cooperative Agreement Guidance for FY 1996'' (spring 1996). Copies of the grant guidance may be obtained through any of EPA's ten regional offices at the addresses listed under Unit V. of this notice. It is important to note, however, that the examples presented in the guidance are not exhaustive, and applicants are not limited in their proposals to the listed tasks. Individual state program innovations are eligible and encouraged, so long as the proposed tasks relate to the purposes set forth in TSCA section 404(g) and fit within one or more of the three general funding categories.

III. Selection Criteria

During the FY96 award cycle, EPA expects between $9,000,000 and $12,500,000 to be available for distribution to eligible applicants. The Agency will use a two-tiered system to

allocate these funds. This system is aimed at achieving the broadest possible state participation, while at the same time, targeting areas with the greatest potential lead hazard and risk. It accomplishes this by providing for a tier-one distribution of ''base funding,'' followed by a tier-two distribution of ''formula funding,'' where additional funds are distributed based upon the relative lead burden estimated to exist within a state. Applicants with funding requirements exceeding the base allotments will be considered for receiving this apportioned additional funding based on two factors: the relative ''lead burden'' allocation and the applicant's demonstration of the State's progress in authorizing a training, accreditation, and certification program for lead-based paint activities.

Each state and the District of Columbia (excluding territories and federally-recognized Indian governing bodies) that submits a qualifying proposal will be entitled to a base funding allotment of $100,000. In addition, base funding of up to $50,000 will be reserved for each of the four ''territories'' (used generically in this context) that have been administratively assigned to an EPA regional office and that have historically participated in EPA toxics cooperative agreement programs. These ''base'' territories include the U.S. Virgin Islands (Region 2), the Commonwealth of Puerto Rico (Region 2), Guam (Region 9), and American Samoa (Region 9). The two remaining ''non-base'' territories, the Canal Zone and the Northern Mariana Islands, are also eligible to apply for funding up to $50,000 apiece, but are not considered in determining the base funding allotments. Base allotments are primarily intended to ensure that those states and base territories wishing to pursue authorization under TSCA section 404 will be guaranteed a minimum level of funding for this purpose. Any unsubscribed base funding will be added to the formula funds pool.

Once base funding allotments have been reserved for all eligible applicants, remaining funds will be treated as ''formula funds.'' Before applying the lead burden formula, however, EPA will set-aside an amount not to exceed $1,500,000 for Federally recognized Indian governing bodies. Indian governing body will be given funding based upon tribal population and if an Indian governing body received funding in the FY 1994 and/or FY 1995 grant process, they will be supported to the same extent in FY96 process. EPA cannot reliably predict the level of participation from Indian governing bodies and non-base territories; therefore, where these eligible parties do apply for funds, they will be assigned to an appropriate regional office for administrative oversight, and that regional office will become responsible for determining the appropriate level of funding. These parties, however, will not receive a formula ranking, and will not be eligible to compete for additional formula allocations based upon lead burden calculations.

As a third step, states and base territories with funding requirements exceeding their base allotments can be given apportioned additional sums based upon their relative lead burden and the progress they have made toward establishing a training, certification, and accreditation program. In calculating lead burden for the formula rankings, EPA used readily available data derived from the 1990 Census of Population and Housing, together with other data from the U.S. Department of Housing and Urban Development (HUD). The formula uses four factors to generate an estimate of the potential lead problem, or ''lead burden,'' in each state. Two of these factors, the number of housing units with lead-based paint and the number of children under age 7, express the potential magnitude of the lead problem. The remaining two factors, the fraction of young children in poverty and the fraction of low-income housing units with lead-based paint, express the potential severity of the problem.

In determining formula rankings, each state and base territory is scored independently for each factor, and the four individual factor scores for the state or base territory are then summed to obtain an overall score for that state or base territory (a combined factor score). The combined factor scores of all states and base territories applying for formula funds (or amounts in excess of their base allotment) are then summed, and the percentage of the total sum represented by the individual state's or base territory's score is then identified. When the total formula funding available is then multiplied by the percentage score of an individual state or territory, the state's or base territory's ceiling formula allotment can be obtained. For example, assume that $12,500,000 are available and: (1) All 50 states but none of the base territories apply for formula allotments, (2) state X has a percentage score of 2 percent, and (3) a total of $4,000,000 in formula funding is available. In determining how much money to allot to state X, EPA would multiply $4,000,000 by .02. The product, $80,000, represents the maximum additional funding that could be awarded to state X to supplement its base allocation. State X would then qualify for up to $180,000 in total funding for the fiscal year ($100,000 in base funding + $80,000 in formula funding).

In general, the maximum, or ceiling, formula allotments will fluctuate inversely with the number of applicants. The greater the number of applicants, the lower the ceiling will tend to be, and vice versa. Formula allotments will be determined only after the annual application deadline has passed and EPA has full knowledge of the total amount of funds requested. If one or more states or base territories request formula fund amounts below their ceiling allotments, residual formula funds will be available. Where this situation develops, if there are still other states or base territories with unfunded needs, the formula will be run again. This procedure can be repeated until all formula funds have been fully allotted.

IV. Submission Requirements

To be considered for funding, each application must include, at a minimum, the following forms and certifications which are contained in EPA's ''Application Kit for Assistance'': (1) Standard Form 424 (Application for Federal Assistance), (2) EPA Form 5700–48 (Procurement Certification), (3) Drug-Free Workplace Certification, (4) Debarment and Suspension Certification, (5) Disclosure of Lobbying Activities, and (6) a return mailing address. In addition to these standard forms, each application must also include a work program, a detailed line-item budget with sufficient information to clearly justify costs, a list of work products or deliverables, and a schedule for their completion. Work programs are to be negotiated between applicants and their EPA regional offices to ensure that both EPA and state priorities can be addressed. In addition, any application from a state, territory or Indian governing body without an authorized program must demonstrate how the proposed activities will lead to that state's pursuit of authorization. Finally, any applicant proposing the collection of environmentally related measurements or data generation must adequately address the requirements of 40 CFR 31.45 relating to quality assurance/quality control. These requirements are more specifically outlined in the ''Guidance Document for the Preparation of Quality Assurance Project Plans'' (May 1993) published by EPA's Office of Pollution Prevention and Toxics. This document, as well as the application kits referred to above, may be obtained from EPA's regional offices.

V. Application Procedures and Schedule

Applications must be submitted to the appropriate EPA regional office in duplicate; one copy to the regional lead program branch and the other to the regional grants management branch. Early consultations are recommended between prospective applicants and their EPA regional offices. Because TSCA Title IV cooperative agreements will be administered at the regional level, these consultations can be critical to the ultimate success of a state's project or program.

For more information about this financial assistance program, or for technical assistance in preparing an application for funding, interested parties should contact the Regional Primary Lead Contact person in the appropriate EPA regional office. The mailing addresses and contact telephone numbers for these offices are listed below.

Region I: (Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, Vermont), JFK Federal Building, One Congress St., Boston, MA 02203. Telephone: (617) 565–3836 (Jim Bryson)
Region II: (New York, New Jersey, Puerto Rico, Virgin Islands), Building 5, SDPTSB, 2890 Woodbridge Ave., Edison, NJ 08837–3679. Telephone: (908) 321–6671 (Lou Bevilacqua)
Region III: (Delaware, Maryland, Pennsylvania, Virginia, West Virginia, District of Columbia), 841 Chestnut Bldg., Philadelphia, PA 19107. Telephone: (215) 597–2450 (Gerallyn Valls)
Region IV: (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), 345 Courtland St., NE, Atlanta, GA 30365. Telephone: (404) 347–3555, ext. 6916 (Roseanne Rudd)
Region V: (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin), SP–14J, 77 W. Jackson St., Chicago, IL 60604. Telephone: (312) 886–7836 (David Turpin)
Region VI: (Arkansas, Louisiana, New Mexico, Oklahoma, Texas), 12th Floor, Suite 2000, 1445 Ross Ave., Dallas, TX 75202. Telephone: (214) 665–7577 (Jeff Robinson)
Region VII: (Iowa, Kansas, Missouri, Nebraska), TOPE/TSC, 726 Minnesota Ave., Kansas City, KS 66101. Telephone: (913) 551–7518 (Mazzie Talley)
Region VIII: (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming), 999 18th St., Suite 500, Denver, CO 80202. Telephone: (303) 312–6021 (David Combs)
Region IX: (Arizona, California, Hawaii, Nevada, American Samoa, Guam), 75 Hawthorne St., San Francisco, CA 94105. Telephone: (415) 744–1129 (Larry Biland)
Region X: (Alaska, Idaho, Oregon, Washington), Toxics Section, 1200 Sixth Ave., Seattle, WA 98101. Telephone: (206) 553–1985 (Barbara Ross)

The deadline for EPA's receipt of final FY96 applications is June 10, 1996. Once the application deadline has passed, EPA will process the formula funding calculations and determine the initial formula ceiling allocations. Final negotiations for the award of cooperative agreements can then proceed, but all FY96 agreements must be executed no later than September 30, 1996.

List of Subjects

Environmental protection, Grants, Lead, Training and accreditation.

Dated: May 2, 1996,

Susan H. Wayland,

Acting Assistant Administrator for Prevention, Pesticides and Toxic Substances.

[FR Doc. 96–11782 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–F

[OPP–30396B; FRL–5367–1]

Lakeshore Enterprises; Approval of Pesticide Product Registrations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This notice announces Agency approval of applications to register the pesticide products Green Screen Bags and Green Screen Powder, containing active ingredients not included in any previously registered products pursuant to the provisions of section 3(c)(5) of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), as amended.

FOR FURTHER INFORMATION CONTACT: By mail: Julie Fry, Biopesticides and Pollution Prevention Division (7501W), Office of Pesticide Programs, Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. Office location and telephone number: Rm. CS51B6, Westfield Building North Tower, 2800 Crystal Drive, Arlington, VA 22202, (703) 308–8673; e-mail: fry.julie@epamail.epa.gov.

SUPPLEMENTARY INFORMATION: EPA issued a notice, published in the Federal Register of November 1, 1995 (60 FR 55577), which announced that Lakeshore Enterprises 2804 Benzie Highway, Benzonia, MI 49616, had submitted applications to register the products Green Screen Bags and Green Screen Powder (File Symbols 69090–R and 69090–E), containing the active ingredient meat meal at 99 percent. The company later published a notice in the Federal Register of February 7, 1996 (61 FR 4662) amending the active ingredient for both products to include red pepper at 1 percent, active ingredients not included in any previously registered products.

The applications were approved on March 19, 1995, as Green Screen Bags (EPA Reg. No. 69090–1) and Green Screen Powder (EPA Reg. No. 69090–2) for agricultural, vegetable, ornamental, turf, tree, vine, and other terrestrial crop uses.

The Agency has considered all required data on risks associated with the proposed use of meat meal and red pepper, and information on social, economic, and environmental benefits to be derived from use. Specifically, the Agency has considered the nature of the chemical and its pattern of use, application methods and rates, and level and extent of potential exposure. Based on these reviews, the Agency was able to make basic health safety determinations which show that use of meat meal and red pepper when used in accordance with widespread and commonly recognized practice, will not generally cause unreasonable adverse effects to the environment.

More detailed information on these registrations is contained in an EPA Pesticide Fact Sheet on meat meal and red pepper.

A copy of this fact sheet, which provides a summary description of the chemical, use patterns and formulations, science findings, and the Agency's regulatory position and rationale, may be obtained from the National Technical Information Service (NTIS), 5285 Port Royal Road, Springfield, VA 22161.

In accordance with section 3(c)(2) of FIFRA, a copy of the approved label and the list of data references used to support registration are available for public inspection in the office of the Product Manager. The data and other scientific information used to support registration, except for material specifically protected by section 10 of FIFRA, are available for public inspection in the Public Response and Program Resources Branch, Field Operations Division (7506C), Office of Pesticide Programs, Environmental Protection Agency, Rm. 1132, CM #2, Arlington, VA 22202 (703-305–5805). Requests for data must be made in accordance with the provisions of the Freedom of Information Act and must be addressed to the Freedom of

Information Office (A-101), 401 M St., SW., Washington, D.C. 20460. Such requests should: (1) Identify the product name and registration number and (2) specify the data or information desired.

Authority: 7 U.S.C. 136.

List of Subjects

Environmental protection, Pesticides and pests, Product registration.

Dated: April 25, 1996.

Flora Chow,

Acting Director, Biopesticides and Pollution Prevention Division, Office of Pesticide Programs.

[FR Doc. 96–11619 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–F

[OPP–181011; FRL–5367–2]

Emergency Exemptions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has granted specific exemptions for the control of various pests to 11 States listed below. A quarantine exemption was granted to the United States Department of Agriculture. These exemptions, issued during the month of March 1996, are subject to application and timing restrictions and reporting requirements designed to protect the environment to the maximum extent possible. EPA has denied specific exemption requests. Information on these restrictions is available from the contact persons in EPA listed below.

DATES: See each specific and quarantine exemption for its effective date.

FOR FURTHER INFORMATION CONTACT: See each emergency exemption for the name of the contact person. The following information applies to all contact persons: By mail: Registration Division (7505W), Office of Pesticide Programs, Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. Office location and telephone number: 6th Floor, CS 1B1, 2800 Jefferson Davis Highway, Arlington, VA (703–308–8417); e-mail: group.ermus@epamail.epa.gov.

SUPPLEMENTARY INFORMATION: EPA has granted specific exemptions to the:

1. Arizona Department of Agriculture for the use of imidacloprid on spinach to control aphids; March 15, 1996, to April 15, 1996. Arizona had initiated a crisis exemption for this use. (Margarita Collantes)

2. California Department of Pesticide Regulation for the use of imidacloprid on spinach to control aphids; March 15, 1996, to March 30, 1996. California had initiated a crisis exemption for this use. (Margarita Collantes)

3. California Department of Pesticide Regulation for the use of maneb on walnuts to control bacterial blight; March 15, 1996, to June 15, 1996. (Dave Deegan)

4. California Department of Pesticide Regulation for the use of methyl bromide on sweet potatoes to control nematodes; March 16, 1996, to March 15, 1997. (Libby Pemberton)

5. California Department of Pesticide Regulation for the use of cymoxanil on tomatoes to control late blight; March 14, 1996, to March 14, 1997. (Libby Pemberton)

6. Delaware Department of Agriculture for the use of metolachlor on spinach to control weeds; March 26, 1996, to January 31, 1997. (Margarita Collantes)

7. Florida Department of Agriculture and Consumer Services for the use of dimethomorph on tomatoes to control late blight; March 14, 1996, to March 13, 1997. (Libby Pemberton)

8. Florida Department of Agriculture and Consumer Services for the use of propamocarb hydrochloride on tomatoes to control late blight; March 14, 1996, to March 13, 1997. (Libby Pemberton)

9. Minnesota Department of Agriculture for the use of sodium bentazon on peas to control canada thistle; March 14, 1996, to July 15, 1996. (Andrea Beard)

10. Oregon Department of Agriculture for the use of ethoprop on hops to control garden symphlans; March 15, 1996, to May 30, 1996. (Margarita Collantes)

11. South Carolina Department of Fertilizer and Pesticide Control for the use of Pirate on cotton to control beet armyworms; March 15, 1996, to September 30, 1996. (Margarita Collantes)

12. Texas Department of Agriculture for the use of carbofuran on cotton to control cotton aphids; March 15, 1996, to September 15, 1996. (Dave Deegan)

13. Texas Department of Agriculture for the use of Pirate on cotton to control beet armyworms; March 1, 1996, to September 30, 1996. (Margarita Collantes)

14. Virginia Department of Agriculture and Consumer Services for the use of imidacloprid on spinach to control aphids; March 15, 1996, to October 31, 1996. (Margarita Collantes)

15. Washington Department of Agriculture for the use of chlorpyrifos on grapes to control mealybugs and cutworms; March 13, 1996, to August 15, 1996. (Andrea Beard)

16. Wisconsin Department of Agriculture, Trade, and Consumer Protection for the use of mancozeb on ginseng to control stem and leaf blight; March 6, 1996, to August 31, 1996. A notice published in the Federal Register of March 6, 1996 (61 FR 8933). For the previous 3 years an emergency exemption has been requested and, a complete application for registration of this use has not been submitted to the Agency. In addition, this emergency exemption has been subject to Special Review. However, without the use of mancozeb significant economic losses would occur. (Margarita Collantes)

EPA has granted a quarantine exemption to the United States Department of Agriculture for the use of methyl bromide on various imported commodities to control various foreign pests at United States ports of entry; March 4, 1996, to March 3, 1999. USDA had initiated crisis exemptions for this use. (Libby Pemberton)

Authority: 7 U.S.C. 136.

List of Subjects

Environmental protection, Pesticides and pests, Crisis exemptions.

Dated: May 1, 1996.

Stephen L. Johnson,

Director, Registration Division, Office of Pesticide Programs.

[FR Doc. 96–11620 Filed 5–9–96; 8:45 am]

BILLING CODE 6560–50–F

FEDERAL DEPOSIT INSURANCE CORPORATION

Sunshine Act Meeting

Pursuant to the provisions of the ''Government in the Sunshine Act'' (5 U.S.C. 552b), notice is hereby given that at 10:00 a.m. on Tuesday, May 7, 1996, the Board of Directors of the Federal Deposit Insurance Corporation met in closed session to consider matters relating to the Corporation's corporate activities.

In calling the meeting, the Board determined, on motion of Vice Chairman Andrew C. Hove, Jr., seconded by Director Joseph N. Neely (Appointive), concurred in by Director Eugene A. Ludwig (Comptroller of the Currency), Director Jonathan L. Fiechter (Acting Director, Office of Thrift Supervision), and Chairman Ricki Helfer, that Corporation business required its consideration of the matters on less than seven days' notice to the public; that no earlier notice of the meeting was practicable; that the public interest did not require consideration of

the matters in a meeting open to public observation; and that the matters could be considered in a closed meeting by authority of subsection (c)(2) of the ''Government in the Sunshine Act'' (5 U.S.C. 552b(c)(2)).

The meeting was held in the Board Room of the FDIC Building located at 550—17th Street, N.W., Washington, D.C.

Dated: May 7, 1996.

Federal Deposit Insurance Corporation.

Valerie J. Best,

Assistant Executive Secretary.

[FR Doc. 96–11920 Filed 5–8–96; 12:34 pm]

BILLING CODE 6714–01–M

Sunshine Act Meeting

Pursuant to the provisions of the ''Government in the Sunshine Act'' (5 U.S.C. 552b), notice is hereby given that the Federal Deposit Insurance Corporation's Board of Directors will meet in open session at 9:00 a.m. on Tuesday, May 14, 1996, to consider the following matters:

Summary Agenda

No substantive discussion of the following items is anticipated. These matters will be resolved with a single vote unless a member of the Board of Directors requests that an item be moved to the discussion agenda.

Disposition of minutes of previous meetings.

Reports of actions approved by an officer of the Corporation pursuant to authority delegated by the Board of Directors.

Memorandum re: 1995 Year-End Financial Management Report.

Memorandum re: Corporate Investment Portfolio Status Report.

Memorandum re: First Quarter 1996 Financial Statements.

Memorandum and resolution re: Final amendments to Part 336 of the Corporation's rules and regulations, entitled ''Employee Responsibilities and Conduct.''

Memorandum and resolution re: Rescission of the Corporation's Statement of Policy and Guidelines for Investments in ''Leeway Securities,'' and its Guidelines for Implementing a Policy of Capital Forbearance.

Discussion Agenda

Memorandum and resolution re: Notice regarding Bank Insurance Fund Semiannual Assessment Rates.

Memorandum and resolution re: Notice regarding Savings Association Insurance Fund Semiannual Assessment Rates.

Memorandum and resolution re: Advance notice of proposed rulemaking on possible revisions to Part 330 of the Corporation's rules and regulations, entitled ''Deposit Insurance Coverage,'' which seeks comment on whether the deposit insurance rules should be simplified and, if so, how.

Memorandum and resolution re: Advance notice of proposed rulemaking which seeks comment on certain issues relating to the recordkeeping and confirmation requirements for securities transactions currently set forth in Part 344 of the Corporation's rules and regulations, entitled ''Recordkeeping and Confirmation Requirements for Securities Transactions.''

Memorandum and resolution re: Joint Policy Statement on Interest Rate Risk which identifies the key elements of sound interest rate risk management and describes prudent principles and practices for each of those elements.

Memorandum re: Proposed memorandum of Understanding between the FDIC and FICO Regarding the Collection of Assessments.

The meeting will be held in the Board Room on the sixth floor of the FDIC Building located at 550—17th Street, N.W., Washington, D.C.

The FDIC will provide attendees with auxiliary aids (e.g., sign language interpretation) required for this meeting. Those attendees needing such assistance should call (202) 416–2449 (Voice); (202) 416–2004 (TTY), to make necessary arrangements.

Requests for further information concerning the meeting may be directed to Mr. Jerry L. Langley, Executive Secretary of the Corporation, at (202) 898–6757.

Dated: May 7, 1996.

Federal Deposit Insurance Corporation.

Jerry L. Langley,

Executive Secretary.

[FR Doc. 96–11921 Filed 5–8–96; 12:34 pm]

BILLING CODE 6714–01–M

FEDERAL EMERGENCY MANAGEMENT AGENCY

Open Meeting, Board of Visitors for the National Fire Academy

AGENCY: Federal Emergency Management Agency (FEMA).

ACTION: Notice of open meeting.

SUMMARY: In accordance with section 10 (a) (2) of the Federal Advisory Committee Act, 5 U.S.C. App. 2, FEMA announces the following committee meeting:

Name: Board of Visitors for the National Fire Academy.

Dates of Meeting: June 27–29, 1996.

Place: Building G Conference Room, National Emergency Training Center, Emmitsburg, Maryland.

Time: June 27, 1996, 8:30 a.m.–5:00 p.m. June 28, 1996, 8:30 a.m.–9:00 p.m. June 29, 1996, 8:30 a.m.–5:00 p.m.

Proposed Agenda: June 27–29: Conduct the On Campus Program Survey and Review the Fiscal Year 1996 and 1997 Budgets.

Supplementary Information: The meeting will be open to the public with seating available on a first-come, first-served basis. Members of the general public who plan to attend the meeting should contact the Office of the Superintendent, National Fire Academy, U.S. Fire Administration, 16825 South Seton Avenue, Emmitsburg, MD 21727, (301) 447–1117, on or before June 10, 1996.

Minutes of the meeting will be prepared and will be available for public viewing in the Office of the Administrator, U.S. Fire Administration, Federal Emergency Management Agency, Emmitsburg, MD 21727. Copies of the minutes will be available upon request 30 days after the meeting.

Dated: April 12, 1996.

Carrye B. Brown,

U.S. Fire Administrator.

[FR Doc. 96–11743 Filed 5–9–96; 8:45 am]

BILLING CODE 6718–01–P

FEDERAL RESERVE SYSTEM

Change in Bank Control Notices; Acquisitions of Shares of Banks or Bank Holding Companies

The notificants listed below have applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire a bank or bank holding company. The factors that are considered in acting on the notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notices are available for immediate inspection at the Federal Reserve Bank indicated. Once the notices have been accepted for processing, they will also be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for that notice or to the offices of the Board of Governors. Comments must be received not later than May 24, 1996.

A. Federal Reserve Bank of Kansas City (John E. Yorke, Senior Vice President) 925 Grand Avenue, Kansas City, Missouri 64198:

1. Ken Bass, McAlester, Oklahoma; to acquire a total of 10 percent; Gary Fugitt, McAlester, Oklahoma, to acquire a total of 50 percent; and Jerry Fugitt, McAlester, Oklahoma, to acquire a total

of 40 percent, of the voting shares of Wilburton State Bancshares, Inc., Wilburton, Oklahoma, and thereby indirectly acquire Wilburton State Bank, Wilburton, Oklahoma.

Board of Governors of the Federal Reserve System, May 6, 1996.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 96–11717 Filed 5–9–96; 8:45 am]

BILLING CODE 6210–01–F

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The applications listed below, as well as other related filings required by the Board, are available for immediate inspection at the Federal Reserve Bank indicated. Once the application has been accepted for processing, it will also be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)). If the proposal also involves the acquisition of a nonbanking company, the review also includes whether the acquisition of the nonbanking company complies with the standards in section 4 of the BHC Act, including whether the acquisition of the nonbanking company can ''reasonably be expected to produce benefits to the public, such as greater convenience, increased competition, or gains in efficiency, that outweigh possible adverse effects, such as undue concentration of resources, decreased or unfair competition, conflicts of interests, or unsound banking practices'' (12 U.S.C. 1843). Any request for a hearing must be accompanied by a statement of the reasons a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute, summarizing the evidence that would be presented at a hearing, and indicating how the party commenting would be aggrieved by approval of the proposal. Unless otherwise noted, nonbanking activities will be conducted throughout the United States.

Unless otherwise noted, comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than June 4, 1996.

A. Federal Reserve Bank of Chicago (James A. Bluemle, Vice President) 230 South LaSalle Street, Chicago, Illinois 60690:

1. Carroll County Bancshares, Inc., Carroll, Iowa; to acquire 100 percent of the voting shares of Nevada Community Bancsahres, Inc., Nevada, Iowa, and thereby indirectly acquire Community Bank, Nevada, Iowa (in organization).

In connection with this application, Nevada Community Bancshares, Inc., Nevada, Iowa, has applied to become a bank holding company by acquiring 100 percent of the voting shares of Community Bank, Nevada, Iowa (in organization).

2. UnionBancorp, Inc., Streator, Illinois; to acquire 100 percent of the voting shares of Prairie Bancorp, Inc., Princeton, Illinois, and thereby indirectly acquire Farmers State Bank of Ferris, Ferris, Illinois; Hanover State Bank, Hanover, Illinois; Bank of Ladd, Ladd, Illinois; First National Bank of Manlius, Manlius, Illinois; Tampico National Bank, Tampico, Illinois; Tiskilwa State Bank, Tiskilwa, Illinois; and and Country Bancshares, Inc., Hull, Illinois, and thereby indirectly acquire Omni Bank, Macomb, Illinois.

B. Federal Reserve Bank of Dallas (Genie D. Short, Vice President) 2200 North Pearl Street, Dallas, Texas 75201-2272:

1. State National Bancshares, Inc., Lubbock, Texas, and State National Bancshares of Delaware, Dover, Delaware; to become bank holding companies by acquiring 100 percent of the voting shares of State National Bancshares of Delaware, Dover, Delaware, and State National Bank of West Texas, Lubbock, Texas, a *de novo* bank.

Board of Governors of the Federal Reserve System, May 6, 1996.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 96–11718 Filed 5–9–96; 8:45 am]

BILLING CODE 6210–01–F

MTB Bank; De Novo Corporation to do Business Under Section 25A of the Federal Reserve Act

An application has been submitted for the Board's approval of the organization of a corporation to do business under Section 25A of the Federal Reserve Act (Edge Corporation) 12 U.S.C. § 611 *et seq.* The Edge Corporation will operate as a subsidiary of the applicant, MTB Bank, New York, New York. The factors that are to be considered in acting on the application are set forth in the Board's Regulation K (12 CFR 211.4).

The application may be inspected at the Federal Reserve Bank of New York or at the Board of Governors. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identify specifically any questions of fact that are in dispute, and summarize the evidence that would be presented at a hearing.

Comments regarding the application must be received by the Reserve Bank indicated or at the offices of the Board of Governors no later than June 7, 1996.

A. Federal Reserve Bank of New York (Christopher J. McCurdy, Senior Vice President) 33 Liberty Street, New York, New York 10045:

1. MTB Bank, New York, New York; to establish MTB International Investment Corporation, New York, New York, a *de novo* Edge Corporation pursuant to Section 25A of the Federal Reserve Act.

Board of Governors of the Federal Reserve System, May 6, 1996.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 96–11719 Filed 5–9–96; 8:45 am]

BILLING CODE 6210–01–F

Government in the Sunshine; Meeting Notice

AGENCY HOLDING THE MEETING: Board of Governors of the Federal Reserve System.

TIME AND DATE: 10:00 a.m., Wednesday, May 15, 1996.

PLACE: Marriner S. Eccles Federal Reserve Board Building, C Street entrance between 20th and 2lst Streets, N.W., Washington, D.C. 20551.

STATUS: Open.

MATTERS TO BE CONSIDERED:

Summary Agenda: Because of their routine nature, no discussion of the following items is anticipated. These matters will be voted on without discussion unless a member of the Board requests that an item be moved to the discussion agenda.

1. Publication for comment of proposed amendments to the Federal Reserve Board's risk-based capital guidelines concerning treatment of collateral transactions.

2. Publication for comment of proposed technical and clarifying amendments to Regulation CC (Availability of Funds and Collection of Checks).

3. Publication for comment of proposed amendments to Regulation Z (Truth in Lending) concerning lenders' liability for disclosure errors in real estate-secured loans and new disclosure rules for debt cancellation contracts.

4. Any items carried forward from a previously announced meeting.

Discussion Agenda: Please note that no discussion items are scheduled for this meeting.

Note: If an item is moved from the Summary Agenda to the Discussion Agenda, discussion of the item will be recorded. Cassettes will then be available for listening in the Board's Freedom of Information Office, and copies can be ordered for $5 per cassette by calling (202) 452–3684 or by writing to: Freedom of Information Office, Board of Governors of the Federal Reserve System, Washington, D.C. 20551.

CONTACT PERSON FOR MORE INFORMATION: Mr. Joseph R. Coyne, Assistant to the Board; (202) 452–3204.

Dated: May 8, 1996.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 96–11869 Filed 5–8–96; 12:28 pm]

BILLING CODE 6210–01–P

Government in the Sunshine; Meeting Notice

AGENCY HOLDING THE MEETING: Board of Governors of the Federal Reserve System.

TIME AND DATE: Approximately 10:15 a.m., Wednesday, May 15, 1996, following a recess at the conclusion of the open meeting.

PLACE: Marriner S. Eccles Federal Reserve Board Building, C Street entrance between 20th and 2lst Streets, N.W., Washington, D.C. 20551.

STATUS: Closed.

MATTERS TO BE CONSIDERED:

1. Personnel actions (appointments, promotions, assignments, reassignments, and salary actions) involving individual Federal Reserve System employees.

2. Any items carried forward from a previously announced meeting.

CONTACT PERSON FOR MORE INFORMATION: Mr. Joseph R. Coyne, Assistant to the Board; (202) 452–3204. You may call (202) 452–3207, beginning at approximately 5 p.m. two business days before this meeting, for a recorded announcement of bank and bank holding company applications scheduled for the meeting.

Dated: May 8, 1996.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 96–11870 Filed 5–8–96; 12:28 pm]

BILLING CODE 6210–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

Statement of Organization, Functions, and Delegations of Authority

Under the authority of Section 6 of Reorganization Plan No. 1 of 1953 and Section 2 of Reorganization Plan No. 3 of 1966, and pursuant to the authorities vested in me as Secretary of Health and Human Services, I hereby make the following changes within the Department of Health and Human Services that affects the U.S. Public Health Service. This Notice amends Part A, Office of the Secretary, Chapter AC, Office of Public Health and Science, as last amended at 60 FR 56605–06. The change is to include the Regional Health Administrator (Regions I–X) and associated staff as part of the Public Health Service. The change follows:

Delete paragraph ''VI. Continuation of the Public Health Service,'' in its entirety and replace with the following:

VI. Continuation of the Public Health Service. The newly established Operating Divisions, the Office of Public Health and Science, and the Regional Health Administrator (Regions I–X) and associated staff shall constitute the Public Health Service.

Dated: April 30, 1996.

Donna E. Shalala,

Secretary.

[FR Doc. 96–11703 Filed 5–9–96; 8:45 am]

BILLING CODE 4150–04–M

Centers for Disease Control and Prevention

[Announcement Number 617]

National Institute for Occupational Safety and Health; Occupational Radiation and Energy-Related Health Research Grants; Notice of Availability of Funds for Fiscal Year 1996

Introduction

The Centers for Disease Control and Prevention (CDC), National Institute for Occupational Safety and Health (NIOSH), announces that applications are being accepted for research projects relating to occupational safety and health concerns associated with occupational exposures to radiation and other hazardous agents at nuclear facilities and in other energy-related industries. Studies in the nuclear power industry and deliberate exposure of human subjects in radiation experiments are outside the scope of this announcement.

CDC is committed to achieving the health promotion and disease prevention objectives of ''Healthy People 2000,'' a national activity to reduce morbidity and mortality and improve the quality of life. This announcement is related to the priority area of Occupational Safety and Health. (For ordering a copy of ''Healthy People 2000,'' see the section ''Where to Obtain Additional Information.'')

Authority

This program is authorized under the Public Health Service Act, as amended, Section 301(a) (42 U.S.C. 241(a)); the Occupational Safety and Health Act of 1970, Section 20 (a) (29 U.S.C. 669(a)). The applicable program regulations include 42 CFR Parts 52 and 74.

Eligible Applicants

Eligible applicants include domestic and foreign non-profit and for-profit organizations, universities, colleges, research institutions, and other public and private organizations, including State and local governments and small, minority and/or woman-owned businesses.

Smoke-Free Workplace

CDC strongly encourages all grant recipients to provide a smoke-free workplace and promote the nonuse of all tobacco products, and Public Law 103–227, the Pro-Children Act of 1994, prohibits smoking in certain facilities that receive Federal funds in which education, library, day care, health care, and early childhood development services are provided to children.

Availability of Funds

Approximately $500,000 is available in fiscal year (FY) 1996 to fund approximately 3 to 5 research project grants. The amount of funding available may vary and is subject to change. Awards will range from $25,000 to $200,000 in total costs (direct and indirect) per year. Awards are expected to begin on or about September 1, 1996. Awards will be made for a 12-month budget period within a project period not to exceed 3 years. Continuation awards within the project period will be made on the basis of satisfactory progress and availability of funds.

Purpose

NIOSH will support hypothesis-testing research projects to identify and

investigate the relationships between health outcomes and occupational exposure to radiation and other hazardous agents, epidemiologic methods research relevant to energy-related occupational health research, and research related to assessing occupational exposures.

Programmatic Interest

The focus of grants should emphasize field research in the following topical areas: (1) Retrospective exposure assessment, (2) radiation measurement issues, (3) non-cancer morbidity and mortality outcomes, (4) meta-analysis and combined analysis methodologies, (5) uncertainty analysis, and (6) studies of current workers.

(1) Retrospective Exposure Assessment

Epidemiologic studies of occupational cohorts frequently involve, and can generally benefit from, retrospective exposure assessment to provide estimates of exposure or categorize groups of workers by common exposure. Exposure assessment in energy-related occupational epidemiology requires evaluating exposures to various hazards including ionizing and non-ionizing radiation, metals, acids, and solvents. Grant opportunities encompass the fields of industrial hygiene and retrospective exposure assessment of health physics dosimetry. Research areas of general interest include investigations of: Methods to use limited data to best advantage, how to treat censored data in retrospective exposure assessment, uncertainty analysis techniques for industrial hygiene exposure data and health physics dosimetry, sampling strategy design to yield a representative understanding of exposed groups, decision logic to select and use the most appropriate exposure metric for epidemiologic and risk assessment use, and, development approaches of ''Homogeneous Exposed Groupings'' and the advantages and limitations for epidemiologic use. Research opportunities of specific interest include: reconstruction and dose adjustment of historic film badges; exposure assessment for acid mists, carcinogenic solvents, exotic metals, and leukemogens; assessment of electromagnetic field exposure; and evaluation of biomarkers of exposure.

(2) Radiation Measurement Issues

This topic will focus on the applicability and utility of both internal and external radiation dose data in epidemiologic research. Examples of such issues include how to use nondetectable values, missing dose data in historical radiation exposure measurements, and the accuracy of historical external dosimetry techniques (film and pocket dosimeters). Additional issues of interest include the use, utility and limitations of internal dosimetry data (historical bioassay and radiochemistry techniques) in epidemiologic studies.

(3) Non-Cancer Morbidity and Mortality Outcomes

The majority of analytical epidemiologic research of health effects of energy-related occupational and environmental exposures has focused historically on the assessment of the association between cancer mortality and exposure to ionizing radiation. Although the importance of this research should not be underestimated, it is essential that other potential adverse health effects, as well as other possible energy-related exposures, be thoroughly evaluated as well. Among these are the possible effects of radiation on the reproductive, neurologic, and immune systems. Chemical exposures highly prevalent in Department of Energy facilities, such as exposures to beryllium and mercury, have also been associated with a variety of disease outcomes, particularly respiratory and neurologic in nature.

(4) Meta-Analysis and Combined Analysis Methodologies

Many of the cohorts at nuclear facilities are not individually large enough to detect statistically significant increases in mortality or incidence for rare cancer types. Methods and analyses for combining data across studies, whether in summary form or as individual data, are valuable to the NIOSH research effort involving energy-related health research.

(5) Uncertainty Analysis

Measures of occupational exposure are inherently uncertain. Even when measures of external radiation exposure are generally available, the models used to estimate organ dose, shallow versus deep dose, neutron dose, etc., are subject to error. Measures of dose derived from biological monitoring of urine, feces, blood, etc., are even less precise. Methods for assessing the degree of error in various estimates of exposure to both ionizing radiation as well as other toxic agents (chemicals, EMF, etc.) are desirable.

(6) Studies of Current Workers

Much of the epidemiologic research on nuclear workers conducted at nuclear facilities and other sites has emphasized retrospective studies. More recently new activities involve environmental restoration, waste management and other work that is not related to the design and production of nuclear weapons. Workers are being exposed to radiation and other hazardous agents under conditions and in processes not previously encountered. Hypothesis-testing research in the areas of exposure assessment, epidemiologic and related studies are needed to evaluate these new conditions and processes and the impact on worker health.

Women and Minority Inclusion Policy

It is the policy of the CDC to ensure that women and racial and ethnic groups will be included in CDC supported research projects involving human subjects, whenever feasible and appropriate. Racial and ethnic groups are those defined in OMB Directive No. 15 and include American Indian, Alaskan Native, Asian, Pacific Islander, Black and Hispanic. Applicants shall ensure that women and racial and ethnic minority populations are appropriately represented in applications for research involving human subjects. Where clear and compelling rationale exist that inclusion is not feasible, this situation must be explained as part of the application. In conducting the review of applications for scientific merit, review groups will evaluate proposed plans for inclusion of minorities and both sexes as part of the scientific assessment and assigned score. This policy does not apply to research studies when the investigator cannot control the race, ethnicity and/or sex of subjects. Further guidance to this policy is contained in the Federal Register, Vol. 60, No. 179, Friday, September 15, 1995, pages 47947–47951.

Evaluation Criteria

Upon receipt, applications will be reviewed by CDC for completeness and responsiveness. Applications determined to be incomplete or unresponsive to this announcement will be returned to the applicant without further consideration. If the proposed project involves organizations or persons other than those affiliated with the applicant organization, letters of support and/or cooperation must be included.

Applications that are complete and responsive to the announcement will be evaluated for scientific and technical merit by an appropriate peer review group convened by CDC in accordance with the review criteria stated below. As part of the initial merit review, a process may be used by the initial review group

in which applications will be determined to be competitive or non-competitive based on their scientific merit relative to other applications received in response to this announcement. Applications judged to be competitive will be discussed and assigned a priority score. Applications determined to be non-competitive will be withdrawn from further consideration and the principal investigator/program director and the official signing for the applicant organization will be promptly notified.

Review criteria for this announcement are as follows:

—Scientific, technical, or medical significance and originality of proposed research;
—Appropriateness and adequacy of the experimental approach and methodology proposed to carry out the research;
—Qualifications and research experience of the Principal Investigator and staff, particularly but not exclusively in the area of the proposed research;
—Availability of resources necessary to perform the research;
—Adequacy of plans to include both sexes and minorities and their subgroups as appropriate for the scientific goals of the research. Plans for the recruitment and retention of subjects will also be evaluated.

The review group will critically examine the submitted budget and will recommend an appropriate budget and period of support for each scored application.

In the secondary (programmatic importance) review, the following factors will be considered:

1. Results of the initial review;
2. Magnitude of the problem in terms of numbers of workers affected;
3. Severity of the disease or injury in the worker population; and
4. Usefulness to applied technical knowledge in the identification, evaluation, and/or control of occupational safety and health hazards.

Applicants will compete for available funds with all other approved applications. The following will be considered in making funding decisions:

1. Quality of the proposed project as determined by peer review;
2. Availability of funds; and
3. Program balance among research areas of the announcement.

Executive Order 12372 Review

Applications are not subject to the review requirements of Executive Order 12372, entitled Intergovernmental Review of Federal Programs.

Public Health System Reporting Requirement

This program is not subject to the Public Health System Reporting Requirements.

Catalog of Federal Domestic Assistance Number

The Catalog of Federal Domestic Assistance number is 93.262.

Other Requirements

Human Subjects

If the proposed project involves research on human subjects, the applicant must comply with the Department of Health and Human Services Regulations (45 CFR Part 46) regarding the protection of human subjects. Assurance must be provided to demonstrate that the project will be subject to initial and continuing review by an appropriate institutional review committee. The applicant will be responsible for providing assurance in accordance with the appropriate guidelines and form provided in the application kit.

Confidentiality Agreement

To comply with the routine uses allowing access to Department of Energy (DOE) Privacy Act systems of records, grantees who will be accessing DOE records to conduct epidemiologic studies and/or other public health activities on behalf of NIOSH will be asked to sign a written statement that documents data security procedures to be maintained by the grantee and an agreement to comply with the privacy and confidentiality requirements of the Privacy Act routine uses and the Memorandum of Understanding between the Department of Energy and the Department of Health and Human Services.

Application Submission and Deadlines

A. Preapplication Letter of Intent

Although not a prerequisite of application, a non-binding letter of intent-to-apply is requested from potential applicants. The letter should be submitted to the Grants Management Officer (whose address is reflected in section B, ''Applications''). It should be postmarked no later than June 10, 1996. The letter should identify the announcement number, name of principal investigator, and specify the priority area to be addressed by the proposed project. The letter of intent does not influence review or funding decisions, but it will enable CDC to plan the review more efficiently, and will ensure that each applicant receives timely and relevant information prior to application submission.

B. Applications

Applicants should use Form PHS–398 (OMB Number 0925–0001) and adhere to the ERRATA Instruction Sheet for Form PHS–398 contained in the Grant Application Kit. Please submit an original and five copies on or before July 10, 1996 to: Ron Van Duyne, Grants Management Officer, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention, (CDC), 255 East Paces Ferry Road, NE., Room 300, MS–E13, Atlanta, GA 30305.

C. Deadlines

1. Applications shall be considered as meeting a deadline if they are either:

A. Received at the above address on or before the deadline date, or

B. Sent on or before the deadline date to the above address, and received in time for the review process. Applicants should request a legibly dated U.S. Postal Service postmark or obtain a legibly dated receipt from a commercial carrier or the U.S. Postal Service. Private metered postmarks shall not be accepted as proof of timely mailings.

2. Applications which do not meet the criteria above are considered late applications and will be returned to the applicant.

Where To Obtain Additional Information

To receive additional written information call (404) 332–4561. You will be asked your name, address, and phone number and will need to refer to Announcement 617. In addition, this announcement is also available through the CDC Home Page on the Internet. The address for the CDC Home Page is http://www.cdc.gov. You will receive a complete program description, information on application procedures, and application forms. If you have questions after reviewing the contents of all the documents, business management technical assistance may be obtained from Georgia Jang, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), 255 East Paces Ferry Road, NE., MS–E13, Atlanta, GA 30305, telephone (404) 842–6796; fax: 404–842–6513; internet: glj2@opspgo1.em.cdc.gov. Programmatic technical assistance may be obtained from Roy M. Fleming, Sc.D., Associate Director for Grants, National Institute for Occupational Safety and Health, Centers for Disease Control and Prevention (CDC), 1600 Clifton Road,

NE., Building 1, Room 3053, MS–D30, Atlanta, GA 30333, telephone: 404–639–3343; fax: 404–639–4616; internet: rmf2@niood1.em.cdc.gov.

Please Refer to Announcement Number 617 When Requesting Information and Submitting an Application

Potential applicants may obtain a copy of ''Healthy People 2000'' (Full Report, Stock No. 017–001–00474–0) or ''Healthy People 2000'' (Summary Report, Stock No. 017–001–00473–1) through the Superintendent of Documents, Government Printing Office, Washington, DC 20402–9325, telephone (202) 512–1800.

Dated: May 2, 1996.

Donald L. Holderman,

Acting Director, National Institute for Occupational Safety and Health, Centers for Disease Control and Prevention (CDC).

[FR Doc. 96–11670 Filed 5–9–96; 8:45 am]

BILLING CODE 4163–19–P

Administration for Children and Families

Submission for OMB Review; Comment Request

Title: Welfare Reform Demonstration: Special Application Form.

OMB No.: 0970–0134.

Description: The form will be used by State welfare agencies to apply for federal waivers under the 30-day waiver approval process proposed by the President in his July 31, 1995, speech to the National Governors' Association. Under the process, requests for waivers of federal law for welfare demonstration projects falling within any of five broad policy areas will be approved by the federal government within 30 days of receipt of this request.

Respondents: State governments.

Annual Burden Estimates:

Instrument	Number of respondents	Number of responses per respondent	Average burden hours per response	Total burden hours
Form	54	1	.75	40.5

Estimated Total Annual Burden Hours: 40.5.

Additional Information: Copies of the proposed collection may be obtained by writing to The Administration for Children and Families, Office of Information Services, Division of Information Resource Management Services, 370 L'Enfant Promenade, S.W., Washington, D.C. 20447, Attn: ACF Reports Clearance Officer.

OMB Comment: OMB is required to make a decision concerning the collection of information between 30 and 60 days after publication of this document in the Federal Register. Therefore, a comment is best assured of having its full effect if OMB receives it within 30 days of publication. Written comments and recommendations for the proposed information collection should be sent directly to the following: Office of Management and Budget, Paperwork Reduction Project, 725 17th Street, N.W., Washington, D.C. 20503, Attn: Ms. Wendy Taylor.

Dated: April 19, 1996.

Roberta Katson,

Director, Office of Information Resource Management Services.

[FR Doc. 96–11702 Filed, 5–9–96; 8:45 am]

BILLING CODE 4184–01–M

Food and Drug Administration

[Docket No. 96F–0136]

Johnson Matthey Chemicals; Filing of Food Additive Petition

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that Johnson Matthey Chemicals has filed a petition proposing that the food additive regulations be amended to provide for the safe use of silver chloride-coated titanium dioxide as a preservative in polymeric coatings for polyolefin films intended for use in contact with food.

DATES: Written comments on petitioner's environmental assessment by June 10, 1996.

ADDRESSES: Submit written comments to the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: Vir D. Anand, Center for Food Safety and Applied Nutrition (HFS–216), Food and Drug Administration, 200 C St. SW., Washington, DC 20204, 202–418–3081.

SUPPLEMENTARY INFORMATION: Under the Federal Food, Drug, and Cosmetic Act (sec. 409(b)(5) (21 U.S.C. 348(b)(5))), notice is given that a food additive petition (FAP 6B4503) has been filed on behalf of Johnson Matthey Chemicals, c/o Technical Assessment Systems, Inc., The Flour Mill, 1000 Potomac St. NW., Washington, DC 20007. The petition proposes to amend the food additive regulations in § 175.320 *Resinous and polymeric coatings for polyolefin films* (21 CFR 175.320) to provide for the safe use of silver chloride-coated titanium dioxide as a preservative in polymeric coatings for polyolefin films intended for use in contact with food.

The potential environmental impact of this action is being reviewed. To encourage public participation consistent with regulations promulgated under the National Environmental Policy Act (40 CFR 1501.4(b)), the agency is placing the environmental assessment submitted with the petition that is the subject of this notice on display at the Dockets Management Branch (address above) for public review and comment. Interested persons may, on or before June 10, 1996, submit to the Dockets Management Branch (address above) written comments. Two copies of any comments are to be submitted, except that individuals may submit one copy. Comments are to be identified with the docket number found in brackets in the heading of this document. Received comments may be seen in the office above between 9 a.m. and 4 p.m., Monday through Friday. FDA will also place on public display any amendments to, or comments on, the petitioner's environmental assessment without further announcement in the Federal Register. If, based on its review, the agency finds that an environmental impact statement is not required and this petition results in a regulation, the notice of availability of the agency's finding of no significant impact and the evidence supporting that finding will be published with the regulation in the Federal Register in accordance with 21 CFR 25.40(c).

Dated: April 23, 1996.

Eugene C. Coleman,

Acting Director, Office of Premarket Approval, Center for Food Safety and Applied Nutrition.

[FR Doc. 96–11789 Filed 5–9–96; 8:45 am]

BILLING CODE 4160–01–F

Health Care Financing Administration

[R–66]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Health Care Financing Administration (HCFA), Department of Health and Human Services, has submitted to the Office of Management and Budget (OMB) the following proposal for the collection of information. Interested persons are invited to send comments regarding the burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the agency's functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

Type of Information Collection Request: Reinstatement, without change, of previously approved collection for which approval has expired; *Title of Information Collection:* Hospice Core Service: Nursing Information Collection; *Form No.:* HCFA–R–66; *Use:* Hospice applying for a waiver to the nursing core services requirements must submit documentation to HCFA supporting their request. *Frequency:* Other, one time only; *Affected Public:* Business or other for-profits and Not-for-profit institutes; *Number of Respondents:* 1; *Total Annual Responses:* 1; *Total Annual Hours Requested:* 1.

To request copies of the proposed paperwork collections referenced above, E-mail your request, including your address, to Paperwork@hcfa.gov, or call the Reports Clearance Office on (410) 786–1326. Written comments and recommendations for the proposed information collections should be sent within 30 days of this notice directly to the OMB Desk Officer designated at the following address: OMB Human Resources and Housing Branch, Attention: Allison Eydt, New Executive Office Building, Room 10235, Washington, D.C. 20503.

Dated: May 2, 1996.

Kathleen B. Larson,

Director, Management Planning and Analysis Staff, Office of Financial and Human Resources, Health Care Financing Administration.

[FR Doc. 96–11651 Filed 5–9–96; 8:45 am]

BILLING CODE 4120–03–P

National Institutes of Health

Division of Research Grants; Notice of Closed Meetings

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following Division of Research Grants Special Emphasis Panel (SEP) meetings:

Purpose/Agenda: To review Small Business Innovation Research.
Name of SEP: Biological and Physiological Sciences.
Date: May 14–15, 1996.
Time: 9:00 a.m.
Place: Savory Suites Hotel, Washington, DC.
Contact Person: Dr. Anita Sostek, Scientific Review Administrator, 6701 Rockledge Drive, Room 5202, Bethesda, Maryland 20892, (301) 435–1260.

Name of SEP: Biological and Physiological Sciences.
Date: May 15, 1996.
Time: 11:00 a.m.
Place: Savoy Suites Hotel, Washington, DC.
Contact Person: Dr. Anita Sostek, Scientific Review Administrator, 6701 Rockledge Drive, Room 5202, Bethesda, Maryland 20892, (301) 435–1260.

This notice is being published less than 15 days prior to the above meetings due to the urgent need to meet timing limitations imposed by the grant review and funding cycle.

Name of SEP: Chemistry and Related Sciences.
Date: June 16–18, 1996.
Time: 8:00 a.m.
Place: Bethesda Hyatt, Bethesda, MD.
Contact Person: Dr. Marjam Behar, Scientific Review Administrator, 6701 Rockledge Drive, Room 5218, Bethesda, Maryland 20892, (301) 435–1180.

Name of SEP: Clinical Sciences.
Date: July 17, 1996.
Time: 8:00 a.m.
Place: Double Tree Hotel, Rockville, MD.
Contact Person: Dr. Gertrude McFarland, Scientific Review Administrator, 6701 Rockledge Drive, Room 4110, Bethesda, Maryland 20892, (301) 435–1284.

Purpose/Agenda: To review individual grant applications.
Name of SEP: Behavioral and Neurosciences.
Date: May 17, 1996.
Time: 2:00 p.m.
Place: NIH, Rockledge 2, Room 5172, Telephone Conference.
Contact Person: Dr. Leonard Jakubczak, Scientific Review Administrator, 6701 Rockledge Drive, Room 5172, Bethesda, Maryland 20892, (301) 435–1247.

This notice is being published less than 15 days prior to the above meeting due to the urgent need to meet timing limitations imposed by the grant review and funding cycle.

Name of SEP: Chemistry and Related Sciences.
Date: June 17, 1996.
Time: 8:00 a.m.
Place: Bethesda Hyatt, Bethesda, MD.
Contact Person: Dr. Marjam Behar, Scientific Review Administrator, 6701 Rockledge Drive, Room 5218, Bethesda, Maryland 20892, (301) 435–1180.

Name of SEP: Biological and Physiological Sciences.
Date: June 19–21, 1996.
Time: 8:30 a.m.
Place: Holiday Inn, Chevy Chase, MD.
Contact Person: Dr. Lynwood Jones, Scientific Review Administrator, 6701 Rockledge Drive, Room 4192, Bethesda, Maryland 20892, (301) 435–1153.

Name of SEP: Behavioral and Neurosciences.
Date: June 26–28, 1996.
Time: 8:00 a.m.
Place: The Jefferson Hotel, Washington, DC.
Contact Person: Dr. David Simpson, Scientific Review Administrator, 6701 Rockledge Drive, Room 5192, Bethesda, Maryland 20892, (301) 435–1278.

Name of SEP: Micobiological and Immunological Sciences.
Date: July 11–12, 1996.
Time: 8:00 a.m.
Place: Holiday Inn, Bethesda, MD.
Contact Person: Dr. Jean Hickman, Scientific Review Administrator, 6701 Rockledge Drive, Room 4178, Bethesda, Maryland 20892, (301) 435–1146.

The meetings will be closed in accordance with the provisions set fort in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Program Nos. 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS).

Dated: May 3, 1996.

Susan K. Feldman,

Committee Management Officer, NIH.

[FR Doc. 96–11642 Filed 5–9–96; 8:45 am]

BILLING CODE 4140–01–M

Substance Abuse and Mental Health Services Administration

Notice of Meetings

Pursuant to Public Law 92–463, notice is hereby given of the following meetings of the SAMHSA Special Emphasis Panel II in May.

A summary of the meetings may be obtained from: Ms. Dee Herman, Committee Management Liaison, SAMHSA Office of Extramural Activities Review, 5600 Fishers Lane, Room 17–89, Rockville, Maryland 20857. Telephone: (301) 443–4783.

Substantive program information may be obtained from the individual named as Contact for each meeting listed below.

The first meeting will include the review, discussion and evaluation of individual grant applications. This discussion could reveal personal information concerning individuals associated with the applications. Accordingly, the meeting is concerned with matters exempt from mandatory disclosure in Title 5 U.S.C. 552b(c)(6) and 5 U.S.C. App. 2, § 10(d).

Committee Name: SAMHSA Special Emphasis Panel II.

Meeting Date: May 7, 1996.

Place: Room 12C–26—Telephone Conference, Parklawn Building, 5600 Fishers Lane, Rockville, Maryland 20852.

Open: May 7, 1996, 12:30 p.m.–1 p.m.

Closed: May 7, 1996, 1:00 p.m.–4:00 p.m.

Contact: Wendy B. Davis, Room 17–89, Parklawn Building, Telephone: (301) 443–9912 and FAX: (301) 443–3437.

The other meetings will include the review, discussion and evaluation of individual contract proposals. These discussions could reveal personal information concerning individuals associated with the proposals and confidential and financial information about an individual's proposal. The discussion may also reveal information about procurement activities exempt from disclosure by statute and trade secrets and commercial or financial information obtained from a person and privileged and confidential. Accordingly, the meetings are concerned with matters exempt from mandatory disclosure in Title 5 U.S.C. 552b (c) (3), (4), and (6) and 5 U.S.C. App. 2, § 10(d).

Committee Name: SAMHSA Special Emphasis Panel II.

Meeting Date: May 8, 1996.

Place: Parklawn Building—Conference Room ''N'', 5600 Fishers Lane, Rockville, Maryland 20852.

Closed: May 8, 1996, 10:00 a.m.–12:00 Noon.

Contact: Constance M. Burtoff, Room 17–89, Parklawn Building, Telephone: (301) 443–0411 and FAX: (301) 443–3437.

Committee Name: SAMHSA Special Emphasis Panel II.

Meeting Dates: May 14, 1996.

Place: Parklawn Building—Conference Room ''C'', 5600 Fishers Lane, Rockville, MD 20852.

Closed: May 14, 1996, 10:00 a.m.—12:00 Noon.

Contact: Ferdinand W. Hui, Ph.D., Room 17–89, Parklawn Building, Telephone: (301) 443–9912 and FAX: (301) 443–3437.

This notice is being published less than 15 days prior to the meetings due to the urgent need to meet timing limitations imposed by the review and funding cycle.

Dated: May 6, 1996.

Jeri Lipov,

Committee Management Officer SAMHSA .

[FR Doc. 96–11715 Filed 5–9–96; 8:45 am]

BILLING CODE 4162–20–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–3778–N–84]

Office of the Assistant Secretary for Community Planning and Development; Federal Property Suitable as Facilities To Assist the Homeless

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Notice.

SUMMARY: This Notice identifies unutilized, underutilized, excess, and surplus Federal property reviewed by HUD for suitability for possible use to assist the homeless.

EFFECTIVE DATE: May 10, 1996.

FOR FURTHER INFORMATION CONTACT: Mark Johnston, Department of Housing and Urban Development, Room 7256, 451 Seventh Street SW, Washington, DC 20410; telephone (202) 708–1226; TDD number for the hearing- and speech-impaired (202) 708–2565, (these telephone numbers are not toll-free), or call the toll-free Title V information line at 1–800–927–7588.

SUPPLEMENTARY INFORMATION: In accordance with the December 12, 1988 court order in *National Coalition for the Homeless* v. *Veterans Administration,* No. 88–2503–OG (D.D.C.), HUD publishes a Notice, on a weekly basis, identifying unutilized, underutilized, excess and surplus Federal buildings and real property that HUD has reviewed for suitability for use to assist the homeless. Today's Notice is for the purpose of announcing that no additional properties have been determined suitable or unsuitable this week.

Dated: May 3, 1996.

Jacquie M. Lawing,

Deputy Assistant Secretary for Economic Development.

[FR Doc. 96–11551 Filed 5–9–96; 8:45 am]

BILLING CODE 4210–29–M

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Klamath River Basin Fisheries Task Force Meeting

AGENCY: U.S. Fish and Wildlife Service, Interior.

ACTION: Notice of meeting.

SUMMARY: Pursuant to section 10(a)(2) of the Federal Advisory Committee Act (5 U.S.C. App. I), this notice announces a meeting of the Klamath River Basin Fisheries Task Force, established under the authority of the Klamath River Basin Fishery Resources Restoration Act (16 U.S.C. 460ss *et seq.*) The meeting is open to the public.

DATES: The Klamath River Basin Fisheries Task Force will meet on June 4, 1996 from 9:00 a.m. to 5:30 p.m. and on June 5, 1996 from 8:00 a.m. to 3:00 p.m.

PLACE: The meeting will be held at the Humboldt State University, Department of Natural Resources, Natural Resources Building, Room No. 101, Arcata, California 95521.

FOR FURTHER INFORMATION CONTACT: Dr. Ronald A. Iverson, Project Leader, U.S. Fish and Wildlife Service, P.O. Box 12006 (1215 South Main), Yreka, California 96097–1006, telephone (916) 842–5763.

SUPPLEMENTARY INFORMATION: The principal agenda items at this meeting will be to review the draft request for proposals to conduct a mid-point program review of the Klamath River Fishery Restoration Program; a decision on adopting a draft Upper Basin Amendment to the Long Range Plan for the Klamath River Basin Conservation Area Fisheries Restoration (KR) Program; a decision on revising the Request for KR Program Proposals and proposal ranking procedures; and a discussion on recommendations to improve hatchery management to minimize hatchery versus wild salmon and steelhead interactions.

For background information on the Klamath River Basin Fisheries Task Force, please refer to the notice of their initial meeting that appeared in the Federal Register on July 8, 1987 (52 FR 25639).

Dated: May 3, 1996.

Thomas Dwyer,

Regional Director.

[FR Doc. 96–11707 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–55–P

Bureau of Land Management

[AK–962–1410–00–P]

Alaska; Notice for Publication; AA–6747–A; Alaska Native Claims Selection

In accordance with Departmental regulation 43 CFR 2650.7(d), notice is hereby given that a decision to issue conveyance under the provisions of Sec. 14(a) of the Alaska Native Claims Settlement Act of December 18, 1971, 43 U.S.C. 1601, 1613(a), will be issued to Alaska Peninsula Corporation, Successor In Interest to Qinuyang Limited, for approximately 12.13 acres. The lands involved are located within Sec. 15, T. 17 S., R. 47 W., Seward Meridian, in the vicinity of South Naknek, Alaska.

A notice of the decision will be published once a week, for four (4) consecutive weeks, in the Anchorage Daily News. Copies of the decision may be obtained by contacting the Alaska State Office of the Bureau of Land Management, 222 West Seventh Avenue, #13, Anchorage, Alaska 99513–7599 ((907) 271–5960).

Any party claiming a property interest which is adversely affected by the decision, an agency of the Federal government or regional corporation, shall have until June 10, 1996 to file an appeal. However, parties receiving service by certified mail shall have 30 days from the date of receipt to file an appeal. Appeals must be filed in the Bureau of Land Management at the address identified above, where the requirements for filing an appeal may be obtained. Parties who do not file an appeal in accordance with the requirements of 43 CFR Part 4, Subpart E, shall be deemed to have waived their rights.

Terrie D. Evarts,

Land Law Examiner, ANCSA Team, Branch of 962 Adjudication.

[FR Doc. 96–11706 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–$$–P

[AK–(962)–1410–00–P]

Notice for Publication; F–19155–22; Alaska Native Claims Selection

On July 20, 1983, a Decision to Issue Conveyance (DIC) was issued to Doyon, Limited and published in the Federal Register (48 FR 33753, July 25, 1983). The DIC was modified in part on August 10, 1984, and published in the Federal Register (49 FR 32468, August 14, 1984).

The DIC of July 20, 1983, is hereby modified by adding a rejection in part of State selection application F–026787 and by adding right-of-way grant F–91558.

A notice of the modified DIC will be published once a week, for four (4) consecutive weeks, in the Fairbanks Daily News-Miner. Copies of the modified DIC may be obtained by contacting the Alaska State Office of the Bureau of Land Management, 222 West Seventh Avenue, #13, Anchorage, Alaska 99513–7599.

Any party claiming a property interest which is adversely affected by the decision, an agency of the Federal government, or regional corporation, shall have until June 10, 1996, to file an appeal on the issue in the modified DIC.

However, parties receiving service by certified mail shall have 30 days from the date of receipt to file an appeal. Appeals must be filed in the Bureau of Land Management at the address identified above, where the requirements for filing an appeal may be obtained. Parties who do not file an appeal in accordance with the requirements in 43 CFR part 4, subpart E, shall be deemed to have waived their rights.

Except as modified by this decision, the decision of July 20, 1983, as modified on August 10, 1984, stands as written.

Elizabeth Sherwood,

Land Law Examiner, ANCSA Team, Branch of 962 Adjudication.

[FR Doc. 96–11594 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–$$–P

[CO–933–96–1320–01; COC 59432]

Colorado; Notice of Invitation for Coal Exploration License Application, Cottonwood Land Company

Pursuant to the Mineral Leasing Act of February 25, 1920, as amended, and to Title 43, Code of Federal Regulations, Subpart 3410, members of the public are hereby invited to participate with Cottonwood Land Company in a program for the exploration of unleased coal deposits owned by the United States of America in the following described lands located in Moffatt and Routt Counties, Colorado:

T. 5 N., R. 88 W., 6th P.M.
- Sec. 4, SE¼NW¼, and SW¼;
- Sec. 5, lots 5 to 9, inclusive, SW¼NE¼, SE¼NE¼, E½SW¼, SW¼SW¼, and SE¼;
- Sec. Tract 37, SW¼NW¼;
- Sec. 6, lots 8 to 23, inclusive;
- Tract 37, SE¼NE¼, and E½SE¼;
- Tract 38, E½SW¼, and W½SE¼;
- Sec. 7, lots 5 to 11, inclusive, lots 13, and 17, S½NE¼, SE½NW¼, and SE¼;
- Tract 39, lots 12, 14 to 16, inclusive;
- Sec. 8, all;
- Sec. 9, NE¼NW¼, W½W½, and SE¼SW¼;
- Sec. 17, N½N½, S½NW¼, and S½SW¼;
- Sec. 18, lots 5, 12, 13, 16, and 17, N½NE¼, and SW¼NE¼;
- Tract 39, lots 6, and 8;
- Tract 40, lots 7, 9 to 11, inclusive, 14, and 15;
- Sec. 19, lots 7, 8, 13, and 14;
- Sec. 20, NW¼, SW¼NE¼, and NW¼SE¼;
- Sec. 30, lots 7, 8, 13, and 14.

T. 5 N., R. 89 W., 6th P.M.
- Sec. 1, lot 8;
- Tract 37, lots 5 to 7, inclusive, and 9 to 20, inclusive;
- Sec. 2, Tract 37, lots 14, 19, 20, and 21;
- Tract 39, lots 5 to 8, inclusive, 11 to 13, inclusive, and 15 to 17, inclusive;
- Tract 42, lots 9, 10, and 18;
- Sec. 3, lots 9, 10, 13, 15, and 19 to 24, inclusive;
- Tract 42, lots 5 to 8, inclusive, 11, 12, 14, 16 to 18, inclusive, 25, and 27;
- Tract 45, lot 26;
- Sec. 4, lots 1 to 4, inclusive, S½N½, and S½;
- Sec. 5, lots 5 to 18, inclusive;
- Tract 43, E½SE¼;
- Tract 44, lot 19;
- Sec. 6, lots 1, 2, 4, 6, 7, S½NE¼, E½SW¼, and SE¼;
- Sec. 7, lots 1 to 4, inclusive, E½, and E½W½;
- Sec. 8, lots 2 to 5, inclusive, 8, 9, 11 to 17, inclusive, and E½NE¼;
- Tract 43, E½NE¼;
- Tract 44, lots 1, 6, 7, and 10;
- Sec. 9, lots 1 to 13, inclusive;
- Sec. 10, lots 2 to 15, inclusive;
- Tract 45, lot 1;
- Sec. 11, lots 6, 8, 10, and 14 to 19, inclusive;
- Tract 37, lots 1 to 5, inclusive, 7, 9, 11, 12, and 20;
- Tract 47, lots 13, and 21;
- Sec. 12, lots 4 to 6, inclusive, and 9 to 11, inclusive;
- Tract 37, lots 1 to 3, inclusive;
- Tract 47, lots 7, and 8;
- Sec. 13, lots 1 to 3, inclusive, and 5 to 17, inclusive;
- Tract 47, lot 4;
- Sec. 14, lots 2, 3, and 5 to 17, inclusive;
- Tract 47, lot 1;
- Tract 52, lot 4, and 10;
- Sec. 15, lots 1 to 16, inclusive;
- Sec. 16, lots 1 to 10, inclusive;
- Sec. 17, all;
- Sec. 20, all;
- Sec. 21, all;
- Sec. 22, all;
- Sec. 23, all;
- Sec. 24, all;
- Sec. 25, all;
- Sec. 26, all;
- Sec. 27, all;
- Sec. 34, N½NE¼;

Sec. 35, N½N½;
Sec. 36, NE¼, and N½NW¼.
T. 5 N., R. 90 W., 6th P.M.
Sec. 1, lots 5, 6, 11 to 14, inclusive, 19, and 20;
T. 6 N., R. 88 W., 6th P.M.
Sec. 31, lots 3, 4 E½SW¼, and SE¼;
Sec. 32, all;
Sec. 33, N½, and N½S½;
Sec. 34, E½NW¼, NE¼SW¼, N½SE¼, and SE¼SE¼;
Sec. 35, S½NW¼, SW¼, W½SE¼, and NE¼SE¼;
T. 6 N., R. 89 W., 6th P.M.
Sec. 19, lots 10, and 11;
Sec. 26, lots 9 to 16, inclusive;
Sec. 27, lots 9, 10, 15, and 16;
Sec. 28, lots 6 to 8, inclusive, and 11;
Sec. 29, lots 13 to 16, inclusive;
Sec. 31, lots 5, 6, and 11;
Sec. 32, lots 3, and 4;
Sec. 33, lots 1 to 12, inclusive, and SW¼;
Sec. 34, lots 1 to 16, inclusive;
Sec. 35, lots 1 to 16, inclusive.

The area described contains approximately 24,668.41 acres.

The application for coal exploration license is available for public inspection during normal business hours under serial number COC 59432 at the Bureau of Land Management (BLM), Colorado State Office, 2850 Youngfield Street, Lakewood, Colorado 80215, and at the BLM Little Snake Resource Area Office, 1280 Industrial Avenue, Craig, Colorado 81625.

Written Notice of Intent to Participate should be addressed to the attention of the following persons and must be received by them within 30 days after publication of the Notice of Invitation in the Federal Register:

Karen Purvis, CO–933, Solid Minerals Team, Resource Services, Colorado State Office, Bureau of Land Management, 2850 Youngfield Street, Lakewood, Colorado 80215

and

Cottonwood Land Company, Richard D. Tifft, III, P.O. Box 881007, Steamboat Springs, Colorado 80488.

Any party electing to participate in this program must share all costs on a pro rata basis with the applicant and with any other party or parties who elect to participate.

Dated: May 2, 1996.

Karen Purvis,

Solid Minerals Team Resource Services.

[FR Doc. 96–11661 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–JB–M

[UT–060–05–3800–006, UTU–72499]

Notice of Availability of Draft Environmental Impact Statement for SUMMO USA Corporation, Lisbon Valley Open Pit Copper Mine in San Juan County, UT

AGENCY: Bureau of Land Management, Department of Interior.

ACTION: Notice of Availability and Public Comment Period for a Draft Environmental Impact Statement prepared for SUMMO USA Corporation's Lisbon Valley Open Pit Copper Mine in San Juan County, Utah.

SUMMARY: Pursuant to Section 202 of the National Environmental Policy Act of 1969, a Draft Environmental Impact Statement (DEIS) has been prepared, under third party contract, by the Bureau of Land Management (BLM), Moab Field Office. The DEIS has been prepared to analyze impacts and alternatives for SUMMO USA Corporation's proposed Lisbon Valley Open Pit Copper MIne. The proposed project would be located on approximately 1000 acres of federal, state, and private lands located in San Juan County, Utah.

Copies of the DEIS can be obtained from the Moab Field Office at 82 East Dogwood Avenue, Moab, Utah, or by calling (801) 259–6111 and requesting a copy of the document. Additionally, copies of the DEIS will be distributed to all attendees at the public scoping meetings, and individuals, agencies or companies that have previously submitted comments or requested to be placed on the mailing list to receive a copy of the DEIS.

DATES: Written comments on the DEIS will be accepted for a period of 45 days following Federal Register publication of the Notice of Availability by the Environmental Protection Agency. The anticipated date of EPA Federal Register publication is May 24, 1996. Comments must therefore be submitted or postmarked no later than July 8, 1996 in order to be considered. Oral and/or written comments may also be presented at a public meeting to be held at the Moab Field Office conference room, at the above listed address, beginning at 7:00 PM, on June 12, 1996.

ADDRESSES: Written comments on the DEIS document should be addressed to: Kate Kitchell, Moab Field Office Manager, Bureau of Land Management, 82 East Dogwood Avenue, Moab, Utah 84532.

FOR FURTHER INFORMATION CONTACT: Lynn Jackson, Project Coordinator, Moab Field Office, Bureau of Land Management, 82 East Dogwood Avenue, Moab, Utah, 84532, (801) 259–6111.

SUPPLEMENTARY INFORMATION: The DEIS analyzes a proposal by SUMMO USA Corporation of Denver, Colorado, to develop an open pit cooper mining and heap leaching operation on approximately 1000 acres of private fee lands, state leases and unpatented mining claims in south Lisbon Valley, located approximately 18 miles southeast of LaSal, Utah, in San Juan County, Utah.

The copper ore would be mined by conventional open pit mining methods utilizing drilling, blasting and ripping of the ore and associated overburden. The overburden would be removed and stockpiled and the ore would be loaded with front end loaders onto haul trucks. The ore would be trucked to a centralized pad area, utilizing 15,000 feet of haul roads, where it would be crushed and stacked. The copper would then be recovered by a heap leaching method, utilizing low concentrations of sulfuric acid. The leached copper solution would be further refined by standard solvent extraction and electrowinning processes.

The facilities are designed to mine an average of 16,500 tons of ore per day, to produce 17,000 tons of 99.99% pure copper cathodes per year. SUMMO would employ up to 105 people at one time over the life of the project. The construction workforce would be approximately 80 people. The project is currently projected to have a 10 year mining life. Processing would continue after mining ceases for an additional year. To the extent possible, reclamation would occur simultaneously with mining. Final closure and reclamation activities would take approximately 5 years.

The DEIS analyzes environmental impacts from SUMMO's proposal, along with four alternatives designed to mitigate environmental impacts associated with this project, as identified during the scoping process. These alternatives are: (1) No Action (2) Open Pit Backfilling (3) Facility Layout, and (4) Waste Rock Selective Handling. BLM's Preferred Alternative is the Facility Layout Alternative, which in essence would allow the project to proceed with modifications to the layout of waste rock dumps to minimize impacts to soils, sedimentation and visual resources. This preferred alternative may be modified in the Final EIS dependent on comments received during the public comment period.

Dated: May 3, 1996.

Brad Palmer,

Acting Moab Field Office Manager.

[FR Doc. 96–11663 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–DQ–M

[CA–026–1020–00]

Notice of Resource Advisory Council Meeting

AGENCY: Bureau of Land Management, Susanville Resource Advisory Council, Susanville, California.

ACTION: Notice of meeting.

SUMMARY: The Bureau of Land Management's Susanville Resource Advisory Council will hold a business meeting and field tour on Friday and Saturday, May 31 and June 1, 1996. The May 31 meeting begins at 10 a.m. at the Likely Fire Hall, Likely, CA. Public comments will be taken at 10:30 a.m. A tour of the Cedar Creek Watershed Restoration Project will follow. The Saturday, June 1 meeting begins at 9 a.m., also at the Likely Fire Hall. During the meeting, the Advisory Council will continue work on development of standards for healthy rangelands and guidelines for livestock grazing.

Summary minutes of the meeting will be maintained in the BLM's Eagle Lake Resource Area Office, 2950 Riverside Drive, Susanville, CA, and will be available for public inspection and reproduction within 30 days following the meeting.

Linda D. Hansen,

Eagle Lake Resource Area Manager.

[FR Doc. 96–11704 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–40–P

[CA–990–0777–68]

Relocation/Change of Address/Office Closure; California

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: On June 6, 1996, the Bureau of Land Management's (BLM) California State Office will move to a new location. This notice provides information regarding that move.

EFFECTIVE DATE: May 10, 1996.

FOR FURTHER INFORMATION CONTACT: Mary Lou West, BLM California State Office (CA–912), 2800 Cottage Way, Room E–2845, Sacramento, California 95825–1889; telephone number 916–979–2835.

SUPPLEMENTARY INFORMATION: Beginning on June 6, 1996, BLM's California State Office will be moving to a new location. The move will affect the following activities or considerations as follows:

(A). Public Access to Records

During the period of May 30 through June 17, 1996, none of the records maintained by that office will be available for public inspection. However, the Public Room will remain open during the move to provide the following limited services: (1) Provide general or recreational information, (2) Distribute forms for the mining claim maintenance fee/waiver filing, (3) Process maintenance fees for existing mining claims, (4) Process new mining claim locations, and (5) Sell maps. It is anticipated that the entire office will be operational, at the new location, on June 17, 1996.

(B). New Street Address and New Mailing Address

2135 Butano Drive, Sacramento, California 95825–0451.

Please address all correspondence to the new address after June 17, 1996.

(C). Telephone Numbers

Existing telephone numbers will remain unchanged after the move.

Dated: May 3, 1996.

Ronald R. Fox,

Deputy State Director, Administration.

[FR Doc. 96–11662 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–40–P

[AK–040–1430–00; AA–77796]

Notice of Realty Action; Recreation and Public Purposes (R&PP) Act Classification; Alaska

AGENCY: Bureau of Land Management, Department of the Interior.

ACTION: Notice.

SUMMARY: The following public lands in the Matanuska-Susitna Borough, Alaska have been examined and found suitable for lease or conveyance to the Veterans of Foreign Wars Mt. McKinley Post No. 3836 under the provisions of the Recreation and Public Purposes Act, as amended (43 U.S.C. 869 *et seq.*). The Veterans of Foreign Wars proposes to use the lands for a recreational park.

Seward Meridian

T. 26 N., R. 5 W.,

Sec. 25, Lot 10, the eastern 132 feet.

Containing 1.0 acre more or less.

FOR FURTHER INFORMATION CONTACT: Martin Hansen, Anchorage District Office, 6881 Abbott Loop Road, Anchorage, Alaska, 907–267–1216.

SUPPLEMENTARY INFORMATION: The lands are outside the Bureau of Land Management's Southwest Management Framework Plan. A plan amendment to cover the area is being prepared.

The lease/patent, when issued, will be subject to the following terms, conditions and reservations:

1. Provisions of the Recreation and Public Purposes Act and to all applicable regulations of the Secretary of the Interior.

2. A right-of-way for ditches and canals constructed by the authority of the United States.

3. All minerals shall be reserved to the United States, together with the right to prospect for, mine, and remove the minerals.

4. Those rights for a sewer line granted to the Matanuska-Susitna Borough by right-of-way AA–57699.

Upon publication of this notice in the Federal Register, the lands will be segregated from all other forms of appropriation under the public land laws, including the general mining laws, except for lease or conveyance under the Recreation and Public Purposes Act and leasing under the mineral leasing laws. For a period of 45 days from the date of publication of this notice in the Federal Register, interested parties may submit comments regarding the proposed lease/conveyance or classification of the lands to the District manager, Anchorage District Office, 6881 Abbott Loop Road, Anchorage, Alaska 99507.

CLASSIFICATION COMMENTS: Interested parties may submit comments involving the suitability of the land for a recreational park. Comments on the classification are restricted to whether the land is physically suited for the proposal, whether the use will maximize the future use or uses of the land, whether the use is consistent with local planning and zoning, or if the use is consistent with State and Federal programs.

APPLICATION COMMENTS: Interested parties may submit comments regarding the specific use proposed in the application and plan of development, whether the BLM followed proper administrative procedures in reaching the decision, or any other factor not directly related to the suitability of the land for a recreation park.

Any adverse comments will be reviewed by the State Director. In the absence of any adverse comments, the classification will become effective 60 days from the date of publication of this notice in the Federal Register.

Dated: May 1, 1996.

Mike Zaidlicz,

Acting District Manager.

[FR Doc. 96–11705 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–JA–P

[NM–010–06–1220–00/G010–G6–0202]

Establishment of Supplementary Rules for Designated Recreation Sites, Special Recreation Management Areas, and Other Public Lands in the Albuquerque District, NM

AGENCY: Bureau of Land Management (BLM), Interior.

ACTION: Final Supplementary Rules.

SUMMARY: Supplementary rulemaking is provided for under Title 43 CFR, Subpart 8365. These rules are needed for managing actions, activities, and use on public lands, including those lands that have been acquired by or conveyed to the BLM. These rules also provide for the protection of persons and resources in the interest and spirit of cooperation with local, state and other federal agencies. Except as otherwise provided by federal law or regulations, state and local laws and ordinances apply and will be enforced by the appropriate state and local authorities.

This notice supersedes previous notices published in the Federal Register (August 17, 1989, Vol. 54, No. 158; and correction to Supplementary Rules No. 2, February 1, 1991, Vol. 56, No. 28) that established supplementary rules for designated recreation sites, special recreation management areas and other public lands in the Albuquerque District, New Mexico.

Proposed supplementary rules to 43 CFR Subparts 8365.1 and 8365.2 for the BLM, Albuquerque District, were published in the Federal Register on August 2, 1995 (Vol. 60, No. 148, pp. 39413–39416), for public comment and review. For a period of 30 days, the public was invited to submit comments on the proposed supplementary rules. Six sets of comments were submitted. Comments were received from four individuals, the Adobe Whitewater Club, and the Open Space Committee for the Village of Placitas. In addition to these respondents, individuals within the agency also commented. Comments ranged from general support of the rules in terms of managing public safety and resource protection, to the disagreement with specific rules. Two comments were on issues beyond the scope of the proposed rules; they refer to activities on nonfederal lands over which the BLM has no jurisdiction. All relevant comments received before this publication have been given special consideration during preparation of these final rules.

A summary follows of the comments received and the BLM's responses to those comments that are relevant to the activities covered by the proposed rules.

One respondent urged the BLM not to ban public nudity, but to allow clothing-optional use. The rule stands as written. In the areas closed to public nudity, visitor use is concentrated because of available recreation opportunities and facilities. Nudity at such locations creates controversy and conflicts among users. In the interest of maintaining order, the banning of nudity at the identified locations will remain. In other areas, nudity is allowed as long as individuals exercise discretion in this activity.

One family submitted a comment offering general support for the rules in terms of public safety and resource protection. However, they wish to see signs about dangerous conditions posted to warn visitors. They do not want other families to have the same heartbreaking experience of losing a family member that they did. Signing and other actions that will be taken to implement these rules are administrative functions separate from these rules. This comment has been accepted for administrative action, but it is not something that can be acted on under this regulatory authority.

This comment also encouraged the BLM to take another look at the rules that provide for cooperation with other state and federal agencies in protecting persons and resources. In the process of reviewing this comment, the BLM has added another rule to address violations of state resource laws [refer below to the fourth rule under the Property and Resources section that supplements CFR 43 8365.1]. This rule enhances interagency cooperation and eliminates the often-lengthy detention of a violator while awaiting arrival of a state officer.

One commentor wants canoes and kayaks exempt from carrying patching and repair equipment and a spare paddle because some of these craft are decked, making it difficult to carry such items. This suggestion has been considered in this final rulemaking for the river segment between Taos Junction and the Taos County Line. Roads parallel this segment and provide a way for boaters to quit and leave the river in case of equipment malfunction or hypothermia, for example. The final rules have been amended to allow the Authorized Officer to stipulate the appropriate equipment as a condition of issuing a recreation use permit for a particular river segment.

Two commentors feel the proposed rules are imposing a discriminatory limitation by restricting their non-commercial boating access to and from the river to only designated sites, while not restricting other river recreation users to such sites. The commentors feel this access limitation could create an unnecessary safety risk to those individuals who have equipment malfunctions or insufficient skills to boat from one designated site to the next during periods of high water. The commentors were also concerned that designated access points would hinder ''location boaters,'' i.e., those who wish to practice on one feature of the river, rather than run an entire segment. However, the BLM does not prohibit boating visitors from exiting the river for safety or emergency reasons such as equipment malfunction or the onset of hypothermia.

The Area Manager retains the right to regulate public use and access where necessary to protect and enhance the resource values of the river shoreline. Such access limitations may also be modified from time to time as a result of changing resource conditions. Designated access locations and limitations are developed with public input, except when closures or limitations must be put in place because use is causing or will cause considerable adverse effects on resources. This comment, which included a list of desirable access sites, has been forwarded to the Area Manager in the Taos Resource Area for consideration in resource management planning efforts involving use of rivers in the Resource Area.

The rule as written has been determined to be excessively restrictive and has been amended. At this time because of problems with congestion from vehicles and user conflicts, the limitation of boat launching and takeout to designated sites will only apply to the Orilla Verde Recreation Area in the segment of the Rio Grande between Taos Junction and the Taos County Line. The requirement for non-commercial boaters to register for each day or multi-day trip has also been dropped.

A commentor also urges the BLM to restrict the area around Manby Hot Springs to day use. This person, who owns property just above Manby Hot Springs, has been experiencing trespass by overnight campers. The rule prohibiting overnight camping at Manby Hot Springs will not change. Trespassing on private lands is a matter beyond the BLM's jurisdiction; complaints of such activities must be handled by local law enforcement agencies.

The Open Space Committee of Placitas identified lands they wish to have closed to target practice and the discharge of firearms. (Some of those identified lands are not under the jurisdiction of the BLM, so the agency cannot impose its supplementary rules on them.) On those public lands identified by the committee, the proposed prohibition on the discharge of firearms (within 150 yards of dwellings, buildings and occupied areas, or in a manner that exposes a person to injury) remains in the final rules for public health and safety reasons. The specific concern of the committee is being addressed under a separate closure authority in another subpart of the Code of Federal Regulations.

Review of the restriction on the discharge of firearms has resulted in the amendment of the sixth prohibition, rule 2 in the Public Health and Safety section of 8365.1. The phrase ''in any manner or place'' was stricken from the rules and replaced with ''recklessly and carelessly.'' As the proposed rule was written, it would have made criminal any person who unknowingly caused damage or injury even if s/he took all reasonable precautions.

Another comment brought to our attention was that the original rule did not address the parking of motorcycles at any approved location within a developed recreation site or area. The third rule under the Occupancy and Use section of 8365.2 has been amended to allow for up to five motorcycles to park at any one approved site. Also, the BLM's patrol of the Tent Rocks has brought to our attention the need to apply an additional rule for resource protection. Campfires within this area have created unacceptable resource conditions, so a rule has now been added to prohibit such use.

In consideration of the comments received, the supplementary rules for the Albuquerque District read as follows.

Definitions: As used in these supplementary rules, the term:

—*Abandonment* means the voluntary relinquishment of control of property for longer than a period specified with no intent to retain possession.

—*Administrative activities* are those activities conducted under the authority of the BLM in accordance with applicable laws, regulations and policies.

—*Authorized Officer* means any employee of the BLM who has been delegated the authority to perform the duties discussed in 43 CFR, Part 8360.

—*Boat launching/taking out* means the transfer of a boat from or to a vehicle or trailer, to or from the water to begin or end a floatboat trip.

—*Campfire* means a controlled fire occurring outdoors for cooking, branding, personal warmth, lighting, ceremonial or aesthetic purposes.

—*Camping* means the erecting of a tent or shelter of natural or synthetic material, preparing a sleeping bag or other bedding material for use, or the parking of a motor vehicle, motor home or trailer for the apparent purpose of overnight occupancy. Occupying a developed campsite or an approved location within developed recreation areas and sites during the established night period of 10 p.m. to 6 a.m. will be considered overnight camping for fee collection and enforcement purposes.

—*Developed recreation sites and areas* are those that contain structures or capital improvements primarily used for recreation purposes by the public. Development may vary from limited improvements for protecting the resources and the safety of users, to distinctly defined sites where developed facilities are provided for concentrated public recreation use. Such sites meet criteria of the Land and Water Conservation Fund Act of 1965 (as amended) for fee collection sites.

—*Disorderly conduct* is engaging in fighting; addressing any offensive, derisive, or annoying communication to any other person who is lawfully present when such communication has a direct tendency to cause acts of violence by the person to whom, individually, the remark is addressed; or making statements or other actions directed toward inciting or producing imminent lawless action and likely to incite or produce such action.

—*Historic or prehistoric structure or ruin site* is any location that meets the standards for inclusion on the National Register of Historic Places as defined in 36 CFR 60.4, without regard to whether the site has been nominated or accepted.

—*Occupancy* means the taking or holding possession of a campsite or residence on public land.

—*Pet* means a dog, cat or any animal that has been domesticated.

—*Public lands* are any lands, interest in lands, or related waters owned by the United States and administered by the BLM. Related waters are those that lie directly over or adjacent to public lands and that require some management control to protect federally administered resources, or to provide for enhanced visitor safety and other recreation experiences.

—*Public nudity* means appearing nude on public lands when such activity is within view of unaffiliated persons. Nudity is defined as the failure to cover the rectal area, pubic area, or genitals. A female is also nude if she fails to cover at least the areola portions of both breasts. Each such covering must be fully opaque. No person under the age of 10 years shall be considered publicly nude.

—*Reasonable quantities* are: for piñon nuts, 25 pounds per year; for seeds, 1 cubic foot per year per species; for other edible plants or plant parts, only the amount that can be personally consumed on site; for woody material, only enough to burn in authorized campfires; for plant materials (or plant parts), 1 cubic foot per species per year; and for specimens and samples of rocks and minerals, small amounts of non-renewable resources used for hobby purposes, not to exceed 250 pounds per year and not to include common mineral materials.

—*Special Recreation Management Area (SRMA)* means an area where special or more intensive types of resource and user management are needed.

—*Stove fire* means a fire built inside an enclosed stove or grill, a portable brazier, or a pressurized liquid or gas stove, including spaceheating devices.

—*Vehicle* means any motorized or mechanized device, not including bicycles or wheelchairs, that is propelled or pulled by any living or other energy source, and is capable of travel by any means over ground or water.

—*Weapon* means a firearm, compressed gas or spring-powered pistol or rifle, bow and arrow, crossbow, blowgun, speargun, slingshot, irritant gas device, explosive device, or any other implement designed to discharge missiles or projectiles; hand-thrown spear, edged weapon, nun-chuck, club, billy-club, or any device modified for use or designed for use as a striking instrument; to include any weapon the possession of which is prohibited under New Mexico law.

Supplementary Rules—All Public Lands

In addition to regulations contained in 43 CFR 8365.1, the following supplementary rules apply to all public lands in the Albuquerque District, including those lands acquired by or conveyed to the BLM, and related waters. Unless authorized by written permission, no person shall:

Sanitation

• Construct or maintain any pit toilet facility, other than shallow holes or

trench toilets developed for use by backcountry visitors for stays lasting 14 days or less. All holes, trenches or pits must be a minimum of 100 feet from any permanent water source.

• Dump or dispose of sewage or sewage treatment chemicals from self-contained or containerized toilets except at facilities provided for that purpose.

Occupancy and Use

• Camp or occupy any site on public lands for a period longer than 14 days within any period of 28 consecutive days. Exceptions, which will be posted, include areas closed to camping and areas or sites with other designated camping stay limits. The 28-day period begins when a camper initially occupies a specific location on public land. The 14-day limit may be reached either through a number of separate visits or through 14 days of continuous occupation. After the 14th day of occupation, campers must move beyond a 25-mile radius from the previous location, and must not return to a location within this radius for 30 days or longer.

• Park any motor vehicle for longer than 30 minutes or camp within 300 yards of any spring, manmade water hole, water well, or watering tank used by wildlife or domestic stock.

• Park or leave a vehicle, or camp at trailheads in violation of posted instructions.

• Dispose of any burning or smoldering material except at sites or facilities provided for that purpose.

• Violate the terms, stipulations, or conditions of any permit or use authorization.

• Fail to show a permit or use authorization to any Bureau of Land Management employee upon request.

• Camp or occupy, or build any fire on or in any historic or prehistoric structure or ruin site.

Vehicles

• Operate an off-road vehicle without full-time use of an approved spark arrester and muffler.

• Operate, park or leave a motorized vehicle in violation of posted restrictions or in such a manner or location as to:

1. Create a safety hazard,
2. Interfere with other authorized users or uses,
3. Obstruct or impede normal or emergency traffic movement,
4. Interfere with or impede administrative activities,
5. Interfere with the parking of other vehicles,
6. Park more than 300 feet from an existing or designated route, subject to any superseding requirements for such use along designated or existing routes, or

• Operate a vehicle in violation of state motor vehicle laws or regulations.

Public Health and Safety

• Possess or use fireworks.

• Sell or make a gift of an alcoholic beverage to a person under 21 years of age.

• Possess an alcoholic beverage if under 21 years of age.

• Ignite or burn any material containing or producing toxic or hazardous material.

• Carry concealed weapons in violation of state law.

• Discharge a firearm or any other implement capable of taking human life, causing injury, or damaging property:

1. In or within 150 yards of a residence, building, campsite, developed recreation site, or occupied area, or
2. On, from or across a developed road; from within a fenced right-of-way; within 40 feet of a road if no fence exists; across a body of water adjacent thereto; or recklessly or carelessly; whereby any person or property is exposed to injury or damage as a result of such discharge.

• Conduct themselves in a disorderly fashion.

• Fail to prevent a pet from harassing, molesting, injuring, or killing humans, domesticated animals, wildlife or livestock.

• Failure to comply with all applicable State of New Mexico regulations for boating safety, equipment, and registration.

• Entering a cave without each person wearing a safety helmet (hard hat) with chin strap and carrying at least three sources of light.

• Possess glass containers where prohibited.

Property and Resources

• Cut, remove, or transport woody materials, including (but not limited to):

1. Any type or variety of vegetation,
2. Fuelwood or firewood (either green or standing deadwood), and
3. Live plants, except as authorized by 43 CFR 8365.1–5 (b) and (c) [which allow the collection of commonly available renewable resources such as flowers, berries, nuts, seeds, cones and leaves; and the collection of forest products for use in campfires on the public lands].

• Remove or transport any mineral resources, including but not limited to rock, sand, gravel, other mineral materials, or decorative landscaping materials on or from public lands without written consent, proof of purchase, or a valid permit.

• Annoy or disturb bats, raptors, reptiles or other protected species, including nesting sites or areas.

• Violate any state laws or regulations concerning conservation or protection of natural resources or the environment, including but not limited to those resources relating to air and water quality, and the protection of fish, wildlife and plants.

Supplementary Rules—Developed Recreation Sites/Areas, Special Recreation Management Areas

In addition to the regulations contained in 43 CFR 8356.1, 8365.2 and those listed above, the following rules will be applied in accordance with 43 CFR 8365.2. Unless authorized by written permit, no person shall:

Occupancy and Use

• Reserve camping space, except at group facilities. Camping space is available on a first-come, first-served basis.

• Camp at one area or site within a developed campground for longer than 7 days in any 28-consecutive-day period unless extended by the authorized officer. After the 7th day, campers must move to a public land site at least 25 miles from the previous location, and must not return to the previous location for 30 days or longer.

• Park more than two 4-wheeled motorized vehicles or five 2- or 3-wheeled motorized vehicles and/or cause an approved site to be used by more than 15 individuals, unless the site is posted otherwise or designated for group use. (Groups exceeding these limits may occupy additional sites and/or additional designated parking areas.)

• Camp or occupy, between 10 pm and 6 am, the Black Rock Spring, County Line, John Dunn Bridge, Lover's Lane, Manby Hot Springs, Quartzite, La Ventana Natural Arch, Tent Rocks, Bluewater Canyon, Cañon Tapia, Guadalupe Ruin and Community, and Ward Ranch Recreation Areas/Sites; Wild Rivers Recreation Area's Bear Crossing and Chawalauna Overlooks; or Orilla Verde Recreation Area's Gauging Station picnic site.

• Engage in noncommercial floatboating without, at a minimum, the following items for each person, boat or group:

1. An approved U.S. Coast Guard Type I, III or V life preserver for each individual, which must be worn at all times while on the rivers;
2. A first aid kit for each group; and
3. Other items that are required to secure a permit for use of a river

segment (including but not limited to fire pans, patching and repair equipment, bailing buckets, extra oars or paddles, air pumps, throw ropes and human waste containers).

• Build, tend, or use a campfire except in a stove, grill, fireplace or ring provided for such purpose in developed recreations areas or sites.

• Build, tend, or use a campfire in the Tent Rocks Recreation Area.

• Ride a horse or bicycle in areas or on trails posted as closed to such use.

• Launch or take out boats, except for emergencies, at any site in the Orilla Verde Recreation Area not designated for such use.

Vehicles

• Use a motorized craft, including inboard or outboard motors, jet skis, personal watercraft or hovercraft on the Rio Grande Wild and Scenic River, and the Lower Gorge Special Recreation Management area between the County Line Recreation Site and the Velarde Diversion Dam; and on the Rio Chama Wild and Scenic River.

• Operate non-street-legal motorized vehicles within the boundaries of all recreation areas or sites.

• Operate motor vehicles within the Ignacio Chavez Grant or Elk Springs during seasonal closures.

• Operate motor vehicles within the San Ysidro Trails Limited Area except as authorized by special use permit.

• Park a vehicle other than in areas established for such use; or further than 25 feet from designated roads, subject to any superseding requirements of such use along wilderness area boundaries, or to restrictions that may be in place along designated roads.

Property and Resources

• Cut or gather green trees or their parts, or remove down or standing dead wood for any purpose, including use in campfires.

• Climb or walk on the ''Tent Rock Formation'' in the Tent Rocks Recreation Area.

• Participate in technical rock climbing within the La Ventana Natural Arch area.

• Use mechanized equipment or create bank disturbance in association with recreational gold panning. (Panning with hand tools below the water line is allowed.)

Public Health, Safety and Comfort

• Fail to immediately remove, and dispose of in a sanitary manner, all pet fecal material, trash, garbage or waste created.

• Bring a pet on any nature or interpretive trails, caves, and freshwater springs that are signed as prohibited to pets. Animals trained to assist handicapped persons are exempt from this rule.

• Fail to maintain quiet between the hours of 10 pm to 6 am, or other hours as posted. During this period no person shall create noise that disturbs other visitors.

• Post or distribute any signs, posters, printed material or commercial advertisements without written approval by the Authorized Officer.

• Use, display or carry weapons within developed campsites or picnic areas.

• Bring equine stock, llamas, cattle or other livestock within campgrounds or picnic areas unless facilities have been specifically provided for such use.

• Discharge firearms or other weapons, or hunt or trap within a developed recreation area, or within ½ mile of a developed recreation site.

• Be publicly nude at Wild Rivers, Orilla Verde or Santa Cruz Lake Recreation Areas; Lower Gorge Special Recreation Management Area; or John Dunn Bridge Recreation Site.

• Shower or bathe at any improved or developed water source, outdoor hydrant pump, faucet or fountain, or restroom water faucet unless such water source is designated for that purpose.

List of Developed Recreation Sites/ Areas and Special Recreation Management Areas in

Rio Puerco Resource Area

1. Tent Rocks
   T. 16 N., R. 5 E., secs. 3, 4, 5
   T. 17 N., R. 5 E., secs. 27–34
2. El Malpais National Conservation Area
   a. La Ventana Natural Arch Special Management Area
   T. 8 N., R. 10 W., secs. 33, 34
   T. 7 N., R. 10 W., secs. 3, 4
   b. South Narrows Recreation Area
   T. 7 N., R. 10 W., sec. 17
   c. El Malpais Ranger Station
   T. 9 N., R. 9 W., sec. 32
3. Elk Springs
   T. 18 N., R. 1 W., secs. 1–4
   T. 19 N., R. 1 W., secs. 10, 11, 14, 15, 21–23, 26–29, 33–35
4. Pronoun Cave Complex
   T. 6 N., R. 5 W., secs. 10, 14
5. Guadalupe Ruin and Community
   T. 15 N., R. 3 W., secs. 14, 15, 22, 23
6. Cañon Tapia (applies only to lands within the canyon)
   T. 15 N., R. 3 W., sec. 20, 21, 22, 29, 31
7. Ignacio Chavez Grant
   T. 15 N., R. 3 W.
   T. 15 N., R. 4 W.
   T. 15 N., R. 5 W.
   T. 15 N., R. 6 W.
   T. 16 N., R. 4 W., secs. 19, 20, 21, 22, 27, 28, 29, 30
   T. 16 N., R. 5 W., secs. 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30
   T. 16 N., R. 6 W.
8. San Ysidro Trials Area
   T. 15 N., R. 1 E., secs. 3, 4, 9, 10
   T. 16 N., R. 1 E.
9. Bluewater Canyon
   a. Canyon Entrance
   T. 12 N., R. 11 W., sec. 5
   b. Lands Within Canyon
   T. 12 N., R. 11 W., secs. 5, 6

Taos Resource Area

1. Lower Gorge Special Recreation Management Area
   T. 26 N., R. 11 E., sec. 31, river section to
   T. 23 N., R. 9 E., sec. 34, including:
   a. Quartzite Recreation Site
   T. 24 N., R. 11 E., sec. 32
   b. County Line Recreation Site
   T. 23 N., R. 11 E., secs. 14, 15
   c. Lover's Lane Recreation Site
   T. 23 N., R. 10 E., sec. 20
2. Orilla Verde Recreation Area
   T. 24 N., R. 11 E., secs. 2, 10, 11, 14–16, 20–22, 28, 29
3. Rio Chama Wild and Scenic River
   T. 24 N., R. 2 E., sec. 1; T. 24 N., R. 3 E., secs. 5, 6, 8–10, 13–15; T. 25 N., R. 2 E., secs. 2, 3, 11, 13, 14, 23, 24, 25, 36; T. 25 N., R. 3 E., sec. 31; T. 26 N., R. 2 E., secs. 3, 4, 9, 10, 15, 16, 21, 22, 26, 27, 34; T. 27 N., R. 2 E., secs. 9, 10, 15, 16, 21, 22, 27, 28, 33, 34
   a. Ward Ranch Recreation Site
   T. 27 N., R. 2 E., sec. 27
4. Rio Grande Wild and Scenic River
   T. 23 N., R. 10 E., secs. 1, 11–16, 22; T. 23 N., R. 11 E., secs. 5–7; T. 24 N., R. 11 E., secs. 2, 10. 11, 15, 16, 20, 21, 28, 29, 31–33; T. 25 N., R. 11 E., secs. 1, 12, 13, 23–26, 35, 36; T. 26 N., R. 11 E., secs. 1, 12–14, 23–26, 35, 36; T. 27 N., R. 11 E., sec. 36; T. 27 N., R. 12 E., secs. 5, 7, 8, 17–19, 30, 31; T. 28 N., R. 12 E., secs. 5–10, 16–20, 29–30; T. 29 N., R. 12 E., secs. 4, 5, 8, 9, 16, 17, 20, 29–32; T. 30 N., R. 12 E., secs. 6, 7, 17–20, 29, 30, 32; T. 31 N., R. 11 E., secs. 1, 2, 11, 14, 23–26; T. 31 N., R. 12 E., secs. 30, 31; and T. 32 N., R. 11 E., secs. 24, 25, 36.
   a. John Dunn Bridge Recreation Site
   T. 27 N., R. 12 E., sec. 31
   b. Manby Hot Springs Recreation Site
   T. 26 N., R. 11 E., sec. 12
   c. Black Rock Spring Recreation Site
   T. 26 N., R. 11 E., sec. 1
5. Santa Cruz Lake Recreation Area
   T. 20 N., R. 10 E., secs. 7, 18
6. Wild Rivers Recreation Area
   T. 29 N., R. 12 E., secs. 16, 17, 20, 29, 31, 32
   T. 28 N., R. 12 E., secs. 4, 5, 6, 8, 9, 16, 17

DATES: The rules are effective on May 10, 1996.

ADDRESSES: Any inquires or suggestions should be addressed to District Manager, BLM, Albuquerque District Office, 435 Montaño Rd. NE, Albuquerque, New Mexico 87107–4935.

FOR FURTHER INFORMATION CONTACT: John Bristol, Resource Program Manager, BLM, Albuquerque District Office, 435 Montaño Rd. NE, Albuquerque, New Mexico 87107–4935, Telephone (505)761–8755.

SUPPLEMENTARY INFORMATION: The New Mexico State Director is establishing these supplementary rules for the Albuquerque District, which are needed to protect persons, property and public lands and resources currently under the BLM's administration. These rules also apply to those lands acquired for inclusion within the administrative jurisdiction of the BLM, as provided for in 43 CFR 8365.1–6. These supplementary rules apply to all persons using public lands. Violations of these rules are punishable by a fine not to exceed $1,000 and/or imprisonment not to exceed 12 months.

Exceptions to these supplementary rules may be allowed by the Authorized Officer under the limits and restrictions of applicable federal and state laws. People granted use exemptions must possess written authorization from the BLM office that has jurisdiction over the area. Users must further comply with the zoning and permitting rules or regulatory requirements of other agencies, where these apply.

So the BLM Albuquerque District can implement these final rules before the beginning of the 1996 summer use season, which starts on Memorial Day weekend, they must be effective on the date of publication. In accordance with the Administrative Procedure Act (5 U.S.C. 531 *et seq.*), the BLM has determined that delaying implementation of these rules for 30 days could impair the protection of persons, property and public lands and resources under the agency's administration. The 30-day delay would be contrary to the public interest and the intended purpose of the rules. The BLM has given interested parties an opportunity to participate in the rulemaking, and has considered public comments in preparing the final rules. Therefore, under the ''good cause'' exception of the Administrative Procedure Act (5 U.S.C. 553(d)(3)) and as discussed above, the BLM has determined that these final rules are excepted from the 30-day delay of their effective date, and are effective on May 10, 1996.

Dated: April 24, 1996.

Lynn Engdahl,

Acting State Director, New Mexico.

[FR Doc. 96–10984 Filed 5–9–96; 8:45 am]

BILLING CODE 4210–29–P

[CA–019–96–1220–24–1A]

Availability of Final Clear Creek Management Area Resource Management Plan Amendment and Environmental Impact Statement

AGENCY: Bureau of Land Management, Department of the Interior.

ACTION: Notice of Availability.

SUMMARY: Pursuant to 40 CFR 1501.7 and 43 CFR 1610.2(c), a final Resource Management Plan Amendment/Environmental Impact Statement (RMP Amendment/EIS) has been prepared by the Hollister Resource Area. The final RMP Amendment/EIS describes and analyzes alternative management scenarios for about 50,000 acres of public lands in the Clear Creek Management Area. These lands are located in south San Benito County in central California.

Decisions relating to the management of the Clear Creek Management Area generated by this planning process will supersede those currently in the Hollister RMP. Copies of the final RMP Amendment/EIS can be obtained or reviewed at the Hollister Resource Area Office, 20 Hamilton Court, Hollister, CA 95023. Since the number of copies available is limited, the Hollister Office has also mailed copies to 27 public libraries in the following locations: Antioch, Fresno, Davis, Gilroy, Fairfield, Hanford, Hayward, Livermore, Madera, Menlo Park, Modesto, Monterey, Oroville, Sacramento, San Francisco, San Jose, San Mateo, San Rafael, Santa Clara, Santa Cruz, Seaside, Sunnyvale, Tracy, Vallejo, Visalia and Yuba City. Public review copies are also available at:

(1) California State Office, 2800 Cottage Way, Sacramento, CA 95825

(2) Bakersfield District Office, 3801 Pegasus Avenue, Bakersfield, CA 93308

Background information and maps used in developing the final RMP Amendment and EIS can be reviewed at the Hollister Resource Area Office.

DATES: The public protest period will run for 30 days after the Environmental Protection Agency (EPA) publishes its notice of availability of this EIS. The publishing date will most likely be May 3, 1996. The public should confirm this date and the end of the protest period by reviewing the EPA Federal Register notice. Protests must be postmarked within 30 days after the EPA has published its notice of availability. Protests must minimally contain the following information: (1) the name, mailing address, telephone number, and interest of the person filing the protest; (2) a statement of the issue or issues being protested; (3) a statement of the part or parts being protested, citing pages, paragraphs, maps, etc. of the RMP Amendment where practical; (4) a copy of all documents addressing the issue(s) for the record; (5) a concise statement of why you believe the BLM State Director's decision is incorrect.

ADDRESSES: Protests should be addressed to: Bureau of Land Management, Division of Planning and Environmental Coordination, 1849 ''C'' Street NW, Washington, D.C. 20240.

SUPPLEMENTARY INFORMATION: The following issues were analyzed and addressed during this planning process: Airborne asbestos emissions, public health risks to environmental asbestos exposure; watershed and riparian resources, endangered and other special status plants and animals, and recreational use. A draft EIS was issued in November of 1993. Six alternatives for management were reviewed in the draft. Alternative 4 of the Draft EIS, which proposed limiting motorcycle use to the Clear Creek watershed while allowing dispersed 4-wheel drive vehicle use in the backcountry, was the BLM proposed alternative. The San Benito Mountain Natural Area was to be expanded to 4,082 acres. Camping would have been eliminated inside the asbestos zone, with the exception of the staging areas. A public wash rack would be constructed, and dust-suppression would be implemented over about 30 miles of main routes. Approximately fifty San Benito evening primrose habitat areas would be protected.

Over 600 comment letters were received from the public and affected agencies. During review of these comments and after reanalysis of Alternative #4, the BLM made several revisions which are published in the Final EIS. Additional impact analysis was incorporated in the biological resource sections. Text in the watershed and soils, human health and recreation sections was modified, expanded and clarified. Additional measures common to all alternatives were drafted, covering education, research, and adherence to best management guidelines for projects affecting watershed stability. Under all alternatives, the 16 known populations of San Benito evening primrose on public land would be protected.

Five of the six alternatives remained unchanged, and one was changed. Alternative 1 remained the ''No Action'' alternative, whereby management would remain at current levels. Fifteen San Benito evening primrose habitat areas would be protected. Alternative 2 (entitled ''Continued Implementation of

the Existing Management Plan'') remained that of implementing the existing (1986) management plan but accelerating completion to a five-year schedule. Approximately fifty San Benito evening primrose habitat areas would be protected.

Alternative 3 was modified and is now the BLM-preferred alternative. Under this alternative (entitled ''Dispersed OHV Use''), most of the Clear Creek Management Area would be managed under a ''Limited Use'' designation for off-highway vehicles (OHVs). BLM would, over the next five years, implement a designated route system of about 270 miles. The final mileage available would be dependent on a variety of factors, including protection of T&E plants, maintenance costs, recreation and administrative access requirements, and compliance. Additionally, alternative 3 would limit unrestricted OHV play on ''barren'' hillslopes to a number of designated play areas. In the transition period, about 207 acres of unrestricted play areas on ''barren'' hillslopes would be available, (down from about 2,800 available now). This acreage could be adjusted up or down depending on resource inventories. Camping would continue to be allowed at the six Staging Areas and at Oak Flat Campground. Backcountry camping would be allowed in designated areas. The San Benito Mountain Natural Area would be expanded to approximately 4,082 acres (this proposal was unchanged from the draft alternative 3), to include a cross-section of unique ecotones associated with the San Benito Mountain forest. A public wash rack would be constructed and about 30 miles of main routes could be dust-suppressed. Approximately fifty San Benito evening primrose habitat areas would be protected.

Alternative 4, entitled ''Restricted OHV use'' remains the same as the draft, and is described above in the discussion of the draft EIS. Alternative 5 (''OHV Closure''), closed the CCMA to motorcycles and restricted 4-wheeled vehicles to the main County road system (about 30 miles). Camping would be limited to Oak Flat Campground only. The San Benito Mountain Natural Area would be expanded to 4,082 acres. Approximately fifty-eight San Benito evening primrose habitat areas would be protected. Alternative 6, (''Enhancement of Natural Values'') would allow vehicle use as under Alternative 5, but would expand the San Benito Mountain Natural Area to include the entire serpentine outcropping (about 30,000 acres). Approximately fifty-eight San Benito evening primrose habitat areas would be protected.

Public participation has occurred throughout the planning process and is encouraged. Anyone wishing additional information may contact the Hollister Resource Area Office, located at 20 Hamilton Court, Hollister, CA 95023 (phone: 408–637–8183).

Dated: May 3, 1996.

Robert E. Beehler,

Hollister Area Manager.

[FR Doc. 96–11659 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–40–P

[CA–019–96–1220–24–1A]

Availability of Proposal To Expand Boundaries of an Existing Area of Critical Environmental Concern (ACEC) in the Clear Creek Management Area, To Rename the San Benito Mountain Outstanding Natural Area To the San Benito Mountain Research Natural Area; Availability of Completion of Previous Planning Decision To Reincorporate 380-Acre San Benito Mountain Natural Area Extension

AGENCY: Bureau of Land Management, Department of the Interior.

ACTION: Notice of availability.

SUMMARY: Pursuant to 43 CFR 1610. 2 (c) and 43 CFR 1610.7(1)(b), a final Resource Management Plan Amendment/Environmental Impact Statement (RMP Amendment/EIS) has been prepared by the Hollister Resource Area. The final RMP Amendment/EIS describes and analyzes alternative management scenarios for about 50,000 acres of public lands in the Clear Creek Management Area. These lands are located in south San Benito and Fresno Counties in central California. This Federal Register notice provides notice about decisions and/or proposed actions regarding two existing designations within the Clear Creek Management Area. The first notice is with regard to the Serpentine Area of Critical Environmental Concern (ACEC), and the second is with regard to the San Benito Mountain Outstanding Natural Area.

(1) Serpentine Area of Critical Environmental Concern. One of the decisions proposed in the Final EIS and RMP Amendment is to expand the existing Serpentine ACEC. The 23,834-acre ACEC was originally designated in 1984 through the public planning process. The Serpentine ACEC was designated because soils in the area contain natural asbestos and there are health issues associated with recreating in the area. It was also designated an ACEC because the vegetative communities associated with serpentine soils are quite unusual.

The Serpentine ACEC boundary was reviewed in 1992 during the EIS process, and adjustments were made based upon soil surveys. The map provided with the final EIS reflects the new known boundaries of the serpentine mass on public land. The adjustments result in a proposed addition of about 10%, or about 2,500 acres, to the geologic boundary line. The changes can be viewed in the ''Errata Sheet'' map included in the Final EIS, or can be reviewed at the locations listed below. The legal description will be published with the Record of Decision for the Final EIS.

(2) San Benito Mountain Natural Area: Given the heavy emphasis of research suggested for this area, the BLM is proposing to change the name of the Natural Area to the ''San Benito Mountain Research Natural Area''. Management of the Natural Area would remain as described in the Final EIS, and the name change would be consistent with the proposed primary use of the area. Finally, to formalize and complete the designation process for this Natural Area, the public is hereby notified that a 380-acre extension approved for re-incorporation under previous planning efforts is now formally re-incorporated into the San Benito Mountain Natural Area. The legal description of this extension is:

Mount Diablo Meridian, California

T. 18S R. 12E
Sec. 14, N½SW¼, SW¼SW¼, N½SE¼ SW¼, and NW¼SE¼;
T. 18S R. 12E
Sec. 15, NW¼NE¼, and E½E½;

In the original 1971 Federal Register notices, the legal description had a typographical error and one omission; both of these have been corrected. Additional copies of maps of both areas and background information can be obtained or reviewed at the Hollister Resource Area Office, 20 Hamilton Court, Hollister, CA 95023. Copies of the Final EIS and maps are available at 27 public libraries in the following locations: Antioch, Fresno, Davis, Gilroy, Fairfield, Hanford, Hayward, Livermore, Madera, Menlo Park, Modesto, Monterey, Oroville, Sacramento, San Francisco, San Jose, San Mateo, San Rafael, Santa Clara, Santa Cruz, Seaside, Sunnyvale, Tracy, Vallejo, Visalia and Yuba City. Public review copies are also available at:

(1) California State Office, 2800 Cottage Way, Sacramento, CA 95825.
(2) Bakersfield District Office, 3801 Pegasus Avenue, Bakersfield, CA 93308

DATES: The public has no later than July 9, 1996 to comment on the proposed expansion of the Serpentine ACEC and the proposed name change for the San Benito Mountain Natural Area.

ADDRESSES: Comments should addressed to: Bureau of Land Management, Hollister Resource Area Office, 20 Hamilton Court, Hollister, CA 95023, Attn: Robert E. Beehler, Area Manager.

SUPPLEMENTARY INFORMATION: (1) Serpentine ACEC: Mining plans of operation must be filed for claims inside an ACEC—thus anyone proposing to operate on a valid claim within the expansion area would need to comply with this regulation. Management of the expansion areas would be the same as within the previous boundaries.

(2) San Benito Mountain Natural Area: The San Benito Mountain Natural Area was designated in 1971. It was designated as an ''Outstanding'' Natural Area, one of the two possible types of Natural Area classifications. The other type of natural area classification is a ''Research'' Natural Area. The original designation was 1,880 acres (August, 1971 36FR16122). In September 1971, 380 acres were withdrawn from the designation because of unresolved mining issues (36FR19177). In 1984, with the development of the Hollister Resource Management Plan, the decision was made to re-incorporate those 380 acres as Natural Area, because the mining claim issue had been resolved. Although this decision was analyzed in the public planning process and ultimately approved, the legal boundaries were never published in the Federal Register. Historic planning maps and documents for the Natural Area and the extension show that there was one portion of the extension which was not described in the Federal Register notice. This portion is in Section 14 and covers a 20-acre segment in the north half of the south-east quarter of the south-west quarter. It is included in this notice. Additionally, a typographical error in the Federal Register notices showed the whole western quarter of Section 15 being included. This should have been the eastern quarter of the section. This has been corrected as well.

Public participation has occurred throughout the planning process and is encouraged. Anyone wishing additional information may contact the Hollister Resource Area Office at the address shown above, or call 408– 637–8183.

Dated: May 3, 1996.

Robert E. Beehler,

Hollister Area Manager.

[FR Doc. 96–11660 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–40–P

DEPARTMENT OF INTERIOR

Bureau of Land Management

[WY–989–1050–00–P]

Filing of Plats of Survey; Wyoming

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: The plats of survey of the following described lands are scheduled to be officially filed in the Wyoming State Office, Cheyenne, Wyoming, thirty (30) calendar days from the date of this publication.

Sixth Principal Meridian, Wyoming

T. 52 N., R. 64 W., accepted April 23, 1996
T. 12 N., R. 114 W., accepted April 23, 1996
T. 13 N., R. 114 W., accepted April 23, 1996
T. 13 N., R. 115 W., accepted April 23, 1996
T. 44 N., R. 118 W., accepted May 1, 1996

Sixth Principal Meridian, Nebraska

T. 26 N., R. 9 E., accepted March 22, 1996
T. 27 N., R. 8 E., accepted April 23, 1996

If protests against a survey, as shown on any of the above plats, are received prior to the official filing, the filing will be stayed pending consideration of the protest(s) and or appeal(s). A plat will not be officially filed until after disposition of protest(s) and or appeal(s).

These plans will be placed in the open files of the Wyoming State Office, Bureau of Land Management, 5353 Yellowstone Road, Cheyenne, Wyoming, and will be available to the public as a matter of information only. Copies of the plats will be made available upon request and prepayment of the reproduction fee of $1.10 per copy.

A person or party who wishes to protest a survey must file with the State Director, Bureau of Land Management, Cheyenne, Wyoming, a notice of protest prior to thirty (30) calendar days from the date of this publication. If the protest notice did not include a statement of reasons for the protest, the protestants shall file such a statement with the State Department within thirty (30) calendar days after the notice of protest was filed.

The above-listed plats represent dependent resurveys, subdivision of sections.

FOR FURTHER INFORMATION CONTACT: Bureau of Land Management, P.O. Box 1828, 5353 Yellowstone Road, Cheyenne, Wyoming 82003.

Dated: May 2, 1996.

Jerry L. Messick,

Acting Chief, Cadastral Survey Group.

[FR Doc. 96–11658 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–22–M

DEPARTMENT OF THE INTERIOR

National Park Service

Notice of Inventory Completion for Native American Human Remains and Associated Funerary Objects from Prince William Sound in the Possession of the Burke Museum, University of Washington, Seattle, WA

AGENCY: National Park Service

ACTION: Notice

Notice is hereby given in accordance with provisions of the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003 (d), of the completion of an inventory of human remains and associated funerary objects in the possession of the Burke Museum, University of Washington, Seattle, WA.

A detailed assessment of the human remains was made by the Burke Museum professional staff in consultation with representatives of the Chugach Alaska Corporation, a Native Alaskan Regional Corporation.

In 1902, human remains representing two individuals were removed from an island cave known as ''Billy's Hole'' in Prince William Sound, Alaska, by Edmond S. Meany and donated to the Burke Museum. No known individuals were identified. The thirteen associated funerary objects include two grave boards, two paddles, a canoe prow, a canoe section, and wooden sticks.

Prior to 1909, a pair of haliotis shell earring were collected by George T. Emmons and accessioned by the Burke Museum in 1909. Accession records indicate these earrings were removed from a ''mummy cave on an island in Prince William Sound (Alaska).''

Archeological and ethnographic evidence from the islands of Prince William Sound, including manner of internment, continuity of technology, and cultural items indicate continuous occupation by the same communities from the precontact period to the present. Oral tradition presented by the representatives of the Chugach Alaska Corporation also supports Chugach occupation of this area throughout this period.

Based on the above mentioned information, officials of the Burke Museum have determined that,

pursuant to 43 CFR 10.2 (d)(1), the human remains from Billy's Hole listed above represent the physical remains of two individuals of Native American ancestry. Officials of the Burke Museum have also determined that, pursuant to 25 U.S.C. 3001 (3)(A), the thirteen objects from Billy's Hole listed above are reasonably believed to have been placed with or near individual human remains at the time of death or later as part of the death rite or ceremony. Officials of the Burke Museum have determined that, pursuant to 25 U.S.C. 3001(3)(B), these two cultural items from a mummy cave in Prince William Sound, AK are reasonably believed to have been placed with or near individual human remains at the time of death or later as part of the death rite or ceremony and are believed, by a preponderance of the evidence, to have been removed form a specific burial site of an Native American individual. Lastly, officials of the Burke Museum have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity which can be reasonably traced between these Native American human remains, associated funerary objects, and unassociated funerary objects and the Chugach Alaska Corporation.

This notice has been sent to officials of the Chugach Alaska Corporation. Representatives of any other Indian tribe that believes itself to be culturally affiliated with these human remains and associated funerary objects should contact Dr. James Nason, Chair of the Repatriation Committee, Burke Museum, Box 353010, University of Washington, Seattle, WA 98195; telephone: (206) 543–9680, before June 10, 1996. Repatriation of the human remains and associated funerary objects, and unassociated funerary objects to the Chugach Alaska Corporation may begin after that date if no additional claimants come forward.

Dated: May 7, 1996

Veletta Canouts

Acting Departmental Consulting Archeologist

Deputy Chief, Archeology & Ethnography Program

[FR Doc. 96–11793 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–70–F

Notice of Inventory Completion for Native American Human Remains from Minnesota in the Possession of the Minnesota Historical Society, St. Paul, MN

AGENCY: National Park Service

ACTION: Notice

Notice is hereby given in accordance with provisions of the Native American Graves Protection and Repatriation Act (NAGPRA), 25 U.S.C. 3003 (d), of the completion of an inventory of human remains in the possession of the Minnesota Historical Society, St. Paul, MN.

A detailed assessment of the human remains was made by Minnesota Historical Society professional staff and Hamline University osteologists in consultation with representatives of the Iowa Tribe of Oklahoma and the Iowa Tribe of Kansas and Nebraska.

In the late 19th century, human remains representing one individual were recovered from the Kitchen Midden site near Cannon Junction, MN. No known individuals were identified. Ceramics found in the feature included examples of Sorg Middle Woodland phase pottery (200 B.C.—ca 300 A.D.). Silvernale phase pottery (1100 A.D.—1300 A.D.) were also observed. The Minnesota Outline of Historic Contexts for the Prehistoric Period tentatively suggests that the Silvernale Phase of the Oneota culture from the vicinity of Red Wing, MN, may represent ancestral Iowa. Geographical location of the site is consistent with the historically documented territory of the Iowa.

In 1979, human remains representing one individual were recovered during legally authorized excavations as part of the Minnesota Statewide Archaeological survey from the Yucatan Village site (21–HU–26) a contact habitation site in the vicinity of Houston MN. No known individuals were identified. The Yucatan Village Site is identified as being occupied during the Orr Phase (1300 A.D. to 1800 A.D.) of the Oneota in the State Site File. Dale R. Henning makes the statement, '' * * *assignment of Ioway to Orr phase can be made fairly definitely.'' Geographic location of the site is consistent with the historically documented territory of the Iowa.

In 1980, human remains representing one individual were recovered during legally authorized excavations as part of the Minnesota Statewide Archaeological survey from Kandiyohi County Park #2 site (21–KH–23) a late precontact habitation site near Willmar, MN. No known individuals were identified. The site is listed as Woodland (ca 500 B.C.—1650 A.D.) in the State Site File. Shell-tempered pottery with a handle fragment and a triangular stone Projectile point were also found at site 21–KH–23, suggesting a more specific occupation of the Orr Phase (1300 A.D.—1800 A.D.) or Ogechie Phase (1400 A.D.—1750 A.D.) of the late Woodland in the State Site File. Dale R. Henning makes the statement, '' * * *assignment of Ioway to Orr phase can be made fairly definitely.'' Geographic location of the site is consistent with the historically documented territory of the Iowa.

Based on the above mentioned information, officials of the Minnesota Historical Society have determined that, pursuant to 43 CFR 10.2 (d)(1), the human remains listed above represent the physical remains of three individuals of Native American ancestry. Officials of the Minnesota Historical Society have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity which can be reasonably traced between these Native American human remains and the Iowa Tribe of Oklahoma and the Iowa Tribe of Kansas and Nebraska.

This notice has been sent to officials of the Iowa Tribe of Oklahoma and the Iowa Tribe of Kansas and Nebraska. Representatives of any other Indian tribe that believes itself to be culturally affiliated with these human remains should contact Marcia G. Anderson, Head of Museum Collections/Chief Curator, Minnesota Historical Society, 345 Kellogg Boulevard West, St. Paul, MN 55102–1906, telephone (612) 296–0150, before June 10, 1996. Repatriation of the human remains and associated funerary objects to the Iowa Tribe of Oklahoma and the Iowa Tribe of Kansas and Nebraska may begin after that date if no additional claimants come forward.

Dated: May 7, 1996

Veletta Canouts

Acting, Departmental Consulting Archeologist

Deputy Chief, Archeology and Ethnography Program

[FR Doc. 96–11792 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–70–F

Notice of Intent to Repatriate a Cultural Item in the Possession of the Peabody Museum of Archaeology and Ethnology, Harvard University, Cambridge, MA

AGENCY: National Park Service

ACTION: Notice

Notice is hereby given under the Native American Graves Protection and Repatriation Act, 25 U.S.C. 3005 (a)(2), of the intent to repatriate a cultural item in the possession of the Peabody Museum of Archaeology and Ethnology, Harvard University, Cambridge, MA, which meets the definition of ''sacred object'' and ''object of cultural patrimony''.

The Beaver bundle consists of a painted elk skin outer wrapping, with

an inner wrapping of bison hide, containing nineteen bird skins or body parts, and a composite consisting of two bird skins; four squirrel, two beaver, four muskrat skins; one mink, one weasel and one fawn skin; also contained are six tied bladder bags, four sticks, a buffalo rib, and a badger skin fur bag containing a bladder bag, tobacco, a bone awl and a beaded fur charm. An auxiliary bundle holds two skin bags containing red and black paint, a skin bag with a buffalo rock, eleven hide rattles, a rectangle of painted rawhide, one rattle of elk hooves, eight sticks, and two braids of sweet grass. Accessories include a pipe stem with a red bayeta case and red bayeta outer wrapping, and a section of wooden broomstick.

The Beaver bundle was obtained by Frank Red Crow in 1942, who sold it to Madge Hardin Walters collecting on behalf of the Denver Art Museum. In 1952 the Denver Art Museum transferred ownership to the Peabody Museum of Archaeology and Ethnology.

Evidence provided by representatives of the Blackfeet Nation acting on behalf of the Blackfeet Confederacy (including the Piegan and Blood First Nations of Canada) shows that the Beaver Bundle is urgently needed for the continued practice of traditional Blackfeet religion by present-day adherents. Representatives of the Blackfeet Nation further state that this item has ongoing traditional and cultural importance to the Confederacy and could not have been conveyed or otherwise alienated by any individual tribal member.

Authorities of the United States Fish and Wildlife Service and State Fish and Wildlife Agencies have been contacted regarding applicability of Federal and State wildlife legislation and have concurred in the conclusion that there are no prohibitions on the transfer of the bundle.

Based on the above-mentioned information, officials of the Peabody Museum of Archaeology and Ethnology have determined that, pursuant to 25 U.S.C. 3001 (3)(C), this cultural item is a specific ceremonial object needed by traditional Native American religious leaders for the practice of traditional Native American religions by their present-day adherents. Officials of the Peabody Museum of Archaeology and Ethnology also have determined that, pursuant to 25 U.S.C. 3001 (3)(D), this cultural item has ongoing historical, traditional, and cultural importance central to the culture itself, and could not have been alienated, appropriated, or conveyed by any individual. Further, Peabody Museum of Archaeology and Ethnology officials have determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity which can be reasonably traced between these items and the Blackfeet Nation.

Representatives of any other Indian tribe that believes itself to be culturally affiliated with this object should contact Mrs. Barbara Isaac, Assistant Director, Peabody Museum of Archaeology and Ethnology, 11 Divinity Avenue, Cambridge, MA 02138, telephone: (617) 495-2254 before June 10, 1996. Repatriation of the object to the Blackfeet Nation may begin after that date if no additional claimants come forward.

Dated: May 6, 1996

Francis P. McManamon

Departmental Consulting Archeologist

Chief, Archeology & Ethnography Program

[FR Doc. 96–11791 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–70–F

Notice of Intent to Repatriate Cultural Items in the Possession of the Arizona State Museum, University of Arizona, Tucson, AZ

AGENCY: National Park Service

ACTION: Notice

Notice is hereby given under the Native American Graves Protection and Repatriation Act, 25 U.S.C. 3005 (a)(2), of the intent to repatriate cultural items in the possession of the Arizona State Museum, University of Arizona, Tucson, AZ, which meet the definition of ''object of cultural patrimony'' under Section 2 of the Act.

The items are a set of San Carlos Apache *Gaan* material consisting of four *Dilzini Gaan* masks, one Clown mask, nine accompanying wands and one associated bull-roarer. All these items are made of painted wood and cloth and were acquired by the Museum in 1985. The material to be repatriated comprises accession number 85–40.

The cultural affiliation of the items is clearly San Carlos Apache as documented in museum records and verified by the San Carlos Apache Tribe. The Tribe has documented that these items have ongoing traditional and cultural importance to the tribe and could not have been conveyed by any individual tribal member.

Based on the above mentioned information, officials of the Arizona State Museum have determined that, pursuant to 25 U.S.C. 3001 (3)(D), these cultural items have ongoing historical, traditional, and cultural importance central to the San Carlos Apache tribe, and could not have been alienated, appropriated, or conveyed by any individual. Arizona State Museum officials have also determined that, pursuant to 25 U.S.C. 3001 (2), there is a relationship of shared group identity which can be reasonably traced between these items and the San Carlos Apache Tribe.

This notice has been sent to officials of the San Carlos Apache Tribe, the Camp Verde Yavapai-Apache Community, the Fort McDowell Mohave-Apache Community, the Payson Tonto Apache Tribe, and the White Mountain Apache Tribe. Representatives of any other Indian tribe that believes itself to be culturally affiliated with these objects should contact Jan Bell, Curator of Collections, Arizona State Museum, University of Arizona, Tucson, AZ 85721, telephone (520) 621–4609 before June 10, 1996. Repatriation of these objects to the San Carlos Apache Tribe may begin after that date if no additional claimants come forward.

Dated: May 1, 1996

Francis P. McManamon

Departmental Consulting Archeologist

Chief, Archeology and Ethnography Program

[FR Doc. 96–11645 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–70–F

Bureau of Reclamation

Bay-Delta Advisory Council Meeting

AGENCY: Bureau of Reclamation, Interior.

ACTION: Notice of meeting.

SUMMARY: The Bay-Delta Advisory Council (BDAC) will meet to discuss several issues including: refinement of the CALFED Bay-Delta Program Draft Alternatives to address the problems of the Bay-Delta system; financial strategy for implementation of the long-term solutions; ecosystem restoration of the Bay-Delta system; issues related to water use efficiency; and other key issues. This meeting is open to the public. Interested persons may make oral statements to the BDAC or many file written statements for consideration.

DATES: The Bay-Delta Advisory Council meeting will be held from 10:00 am to 5:00 pm on Wednesday, May 29, 1996.

ADDRESSES: The Bay-Delta Advisory Council will meet at the Sacramento Convention Center, 1400 J Street, Sacramento, CA.

CONTACT PERSON FOR MORE INFORMATION: Sharon Gross, CALFED Bay-Delta Program, at (916) 657–2666. If reasonable accommodation is needed due to a disability, please contact the Equal Employment Opportunity Office

at (916) 653–6952 or TDD (916) 653–6934 at least one week prior to the meeting.

SUPPLEMENTARY INFORMATION: The San Francisco Bay/Sacramento-San Joaquin Delta Estuary (Bay-Delta system) is a critically important part of California's natural environment and economy. In recognition of the serious problems facing the region and the complex resource management decisions that must be made, the state of California and the Federal government are working together to stabilize, protect, restore, and enhance they Bay-Delta system. The State and Federal agencies with management and regulatory responsibilities in the Bay-Delta system are working together as CALFED to provide policy direction and oversight for the process.

One area of Bay-Delta management includes the establishment of a joint State-Federal process to develop long-term solutions to problems in the Bay-Delta system related to fish and wildlife, water supply reliability, natural disasters, and water quality. The intent is to develop a comprehensive and balanced plan which addresses all the resource problems. This effort, the CALFED Bay-Delta Program (Program), is being carried out under the policy direction of CALFED. The CALFED Bay-Delta Program is exploring and developing a long-term solution for a cooperative planning process that will determine the most appropriate strategy and actions necessary to improve water quality, restore health to the Bay-Delta ecosystem, provide for a variety of beneficial uses, and minimize Bay-Delta system vulnerability. A group of citizen advisors representing California's agricultural, environmental, urban, business, fishing, and other interests who have a stake in finding long term solutions for the problems affecting the Bay-Delta system has been chartered under the Federal Advisory Committee Act (FACA) as the Bay-Delta Advisory Council (BDAC) to advise CALFED on the program mission, problems to be addressed, and objectives for the CALFED Bay-Delta Program. BDAC provides a forum to help ensure public participation, and will review reports and other materials prepared by CALFED staff.

Minutes of the meeting will be maintained by the CALFED Bay-Delta Program, Suite 1155, 1416 Ninth Street, Sacramento, CA 95814, and will be available for public inspection during regular business hours, Monday through Friday within 30 days following the meeting.

Dated: May 3, 1996.

Roger Patterson,

Regional Director, Mid-Pacific Region.

[FR Doc. 96–11783 Filed 5–9–96; 8:45 am]

BILLING CODE 4310–94–M

DEPARTMENT OF JUSTICE

Notice of Consent Decrees in Comprehensive Environmental Response, Compensation and Liability Act Action; Al/co et al.

Notice is hereby given that two consent decrees in *United States et al.* v. *ALCOA et al.*, Civil Action No. 89–7421, were lodged with the United States District Court for the Eastern District of Pennsylvania on April 24, 1996.

On October 16, 1989, the United States filed a complaint against 18 generator and owner/operator defendants under Section 107(a) of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), 42 U.S.C. 9607(a), for response costs incurred and to be incurred by the United States at the Moyer Landfill Superfund Site in Collegeville, Pennsylvania (the ''Site''). The Commonwealth of Pennsylvania (''Commonwealth'') joined the action as plaintiff seeking reimbursement of its response costs incurred and to be incurred at the Site. One of the proposed consent decrees resolves the liability of Alco Industries, Cabot Corporation, and Richardson-Vicks, subject to reopeners for new information and new site conditions, and cost overruns above $55 million, for a payment of $11.5 million in reimbursement of response costs to the United States and the Commonwealth. The other proposed consent decree resolves the liability of William M. Wilson's Sons, Inc., Waste Conversion, Inc., Hatfield Packing Company, Moyer Packing Company, Superior Tube Company, W.R. Grace & Co., Union Carbide Corporation, Henkel Corporation, Ford Electronics and Refrigeration Corporation and Zenith Electronics Corporation, subject to reopeners for new information and new site conditions, and cost overruns above $60 million, for payments totalling $9,558,551 in reimbursement of response costs to the United States and the Commonwealth. Under both decrees the United States receives 84% and the Commonwealth receives 16% of the payments. The Consent Decree includes covenants not to sue under Sections 106 and 107 of CERCLA and under Section 7003 of the Resource Conservation and Recovery Act (''RCRA''), 42 U.S.C. § 6973.

The Department of Justice will accept written comments relating to these proposed Consent Decrees for thirty (30) days from the date of publication of this notice. Please address comments to the Assistant Attorney General, Environment and Natural Resources Division, Department of Justice, P.O. Box 7611, Ben Franklin Station, Washington, D.C. 20044 and refer to *United States et al.* v. *ALCOA et al.*, DOJ No. 90–11–3–145. Commenters may request an opportunity for a public meeting in the affected area, in accordance with Section 7003(d) of RCRA.

Copies of the proposed Consent Decrees may be examined at the Office of the United States Attorney, Eastern District of Pennsylvania, 615 Chestnut Street, Suite 1300, Philadelphia, PA 19106; Region III Office of the Environmental Protection Agency, 841 Chestnut Building, Philadelphia, Pennsylvania 19107; and at the Consent Decree Library, 1120 G Street, N.W., 4th Floor, Washington, D.C. 20005 ((202) 624–0892). A copy of the proposed decrees may be obtained in person or by mail from the Consent Decree Library, 1120 G Street, N.W. 4th Floor, Washington, D.C. 20005. When requesting a copy of the proposed Consent Decrees, please enclose a check payable to the ''Consent Decree Library'' in the following amounts:

$7.50 for the 1st decree described above.

$10.00 for the 2nd decree described above.

Joel M. Gross,

Chief, Environmental Enforcement Section, Environment and Natural Resources Division, U.S. Department of Justice.

[FR Doc. 96–11653 Filed 5–9–96; 8:45 am]

BILLING CODE 4410–01–M

Notice of Lodging of Consent Decree Pursuant to the Clean Water Act

In accordance with Department of Justice policy, 28 C.F.R. 50.7, notice is hereby given that a Consent Decree in *United States* v. *Martin H. Frimberger, et al.*, Civil No. 3:90CV136 (DJS) (D. Conn.), was lodged with the United District Court for the District of Connecticut on March 29, 1996.

The proposed Consent Decree concerns alleged violations of sections 301(a) and 404 of the Clean Water Act, 33 U.S.C. 1311(a) and 1344. Defendant Martin H. Frimberger placed fill material and structures in navigable waters of the United States along the shoreline of the property at 207 Ayers

Road, Old Saybrook, Connecticut, without a permit as required by 33 U.S.C. 1344. Defendants Maia and Kathryn Chiat, successors in title to the property, will perform certain removal and restoration work and will apply to the Army Corps of Engineers for a permit to maintain the fill remaining after the restoration work is completed.

The United States Attorney's Office will receive written comments relating to the proposed Consent Decree for a period of 30 days from the date of publication of this notice. Comments should be addressed to John B. Hughes, Esq., Assistant U.S. Attorney, District of Connecticut, P.O. Box 1824, New Haven, Connecticut 06508, and should refer to *United States* v. *Martin H. Frimberger, Citicorp Mortgage, Inc. and Maia and Kathryn Chiat,* Civil No. 3:90CV136 (DJS) (D. Conn.).

The Complaint and proposed Consent Decree in this case may be examined at the Clerk's Office, United States District Court for the District of Connecticut, 450 Main Street, Hartford, Connecticut 06103.

Letitia J. Grishaw,

Chief, Environmental Defense Section, Environmental & Natural Resources Division.

[FR Doc. 96–11655 Filed 5–9–96; 8:45 am]

BILLING CODE 4410–01–M

Notice of Lodging of Consent Decree Pursuant to the Clean Water Act

In accordance with Department of Justice policy, 28 C.F.R. 50.7, notice is hereby given that a proposed Final (Consent) Judgment in *United States* v. *Seminole Fertilizer Corp.,* Case No. 96–735–CIV–T–24B (M.D. Fla.), was lodged with the United States District Court for the Middle District of Florida on April 15, 1996.

The proposed Final (Consent) Judgment concerns alleged violations of section 301(a) and 404 of the Clean Water Act, 33 U.S.C. 1311(a) and 1344. Specifically, Defendant Seminole Fertilizer Corporation exceeded the terms of a permit issued by the Corps of Engineers under Clean Water Act section 404 in connection with Seminole's phosphate mining operations. As a result of the alleged violation, fill material was unlawfully discharged into approximately 15.0 unpermitted acres of wetlands. The proposed Final (Consent) Judgment would require Seminole Fertilizer Corporation to complete an on-site mitigation project and to pay a $40,000 civil penalty.

The United States Attorney's Office will receive written comments relating to the proposed Final (Consent) Judgment for a period of 30 days from the date of publication of this notice. Comments should be addressed to Michael A. Cauley, Assistant U.S. Attorney, Middle District of Florida, 500 Zack Street, Room 400, Tampa, FL 33602, and should refer to *United States* v. *Seminole Fertilizer Corp.,* Case No. 96–735–CIV–T–24B (M.D. Fla.).

The Complaint and proposed Final (Consent) Judgment in this case may be examined at the Clerk's Office, United States District Court for the Middle District of Florida, 611 North Florida Avenue, Tampa, Florida 33602.

Letitia J. Grishaw,

Chief, Environmental Defense Section, Environmental & Natural Resources Division.

[FR Doc. 96–11656 Filed 5–9–96; 8:45 am]

BILLING CODE 4410–01–M

Notice of Lodging of Consent Decree Pursuant to the Clean Water Act

In accordance with Departmental policy, 28 C.F.R. § 50.7, notice is hereby given that a consent decree in *United States of America* v. *Robert V. Spiller,* CV–96–1010 (W.D. La.), was lodged with the United States District Court for the Western District of Louisiana on April 23, 1996. The proposed decree concerns alleged violations of the Clean Water Act, 33 U.S.C. § 1311, as a result of the discharge of fill materials onto approximately 7.2 acres of wetlands by Roger V. Spiller (''Spiller''), near New Iberia, Louisiana.

The Consent Decree provides for the payment of a $2,000.00 civil penalty to the United States and requires partial restoration of the violation site in accord with a partial restoration plan approved by the United States Environmental Protection Agency (''EPA'').

The Department of Justice will receive written comments relating to the consent decree for a period of thirty (30) days from the date of this notice. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, U.S. Department of Justice, Attention: John A. Sheehan, Environmental Defense Section, P.O. Box 23986, Washington, D.C. 20026–3986, and should refer to *United States* v. *Spiller,* DJ Reference No. 90–5–1–1–4132.

The proposed consent decree may be examined at the Offices of the United States Attorney for the Western District of Louisiana, 600 Jefferson Street, Suite 1000, Lafayette, Louisiana 70501; the offices of Region VI of the United States Environmental Protection Agency, 1445 Ross Avenue, Dallas, Texas 75202, and at the Consent Decree Library, 1120 G Street, N.W., 4th Floor, Washington, D.C. 20005. In requesting a copy, please enclose a check in the amount of $7.75 for a copy of the consent decree with attachments.

Letitia J. Grisaw,

Chief, Environmental Defense Section, Environment and Natural Resources Division, United States Department of Justice.

[FR Doc. 96–11654 Filed 5–9–96; 8:45 am]

BILLING CODE 4410–01–M

Antitrust Division

United States of America v. Woman's Hospital Foundation & Woman's Physician Health Organization; Proposed Final Judgment and Competitive Impact Statement

Notice is hereby given pursuant to the Antitrust Procedures and Penalties Act, 15 U.S.C. 16(b)–(h), that a proposed Final Judgment, Stipulation, and a Competitive Impact Statement have been filed with the United States District Court for the Middle District of Louisiana in *United States of America* v. *Woman's Hospital Foundation & Woman's Physician Health Organization,* Civil No. 96–389–BM2.

The complaint alleges that defendants entered into an agreement that unreasonably restrained competition among physicians in the Baton Rouge, Louisiana area, in violation of Section 1 of the Sherman Act, 15 U.S.C. 1. The complaint also alleges that Woman's Hospital Foundation willfully attempted to maintain and maintained its monopoly in inpatient obstetrical services in the Baton Rouge, Louisiana area, in violation of Section 2 of the Sherman Act, 15 U.S.C. 2.

The proposed Final Judgment, agreed to by the defendants, prohibits defendants' unlawful agreement and the additional acts of Woman's Hospital Foundation that gave rise to the violations of Section 2.

Public comment on the proposed Final Judgment is invited within the statutory 60-day comment period. Such comments and responses thereto will be published in the Federal Register and filed with the Court. Comments should be directed to Gail Kursh, Chief; Health Care Task Force; United States Department of Justice; Antitrust Division; 325 7th Street, NW.; Room

400; Washington, DC, 20530 (telephone: 202/307–5799).

Rebecca P. Dick,

Deputy Director, Office of Operations, Antitrust Division, U.S. Department of Justice.

United States District Court for the Middle District of Louisiana

In the matter of: United States of America, plaintiff, vs. Woman's Hospital Foundation and Woman's Physician Health Organization, Defendants. Civil Action No: 96–389–B–M2; Filed: April 23, 1996.

Stipulation

The parties, by their attorneys, stipulate that:

1. The Court has jurisdiction over the subject matter of this action and over each party, and venue is proper in the Middle District of Louisiana.

2. The Court may file and enter a Final Judgment in the attached form upon the Court's motion or the motion of a party, after compliance with the Antitrust Procedures and Penalties Act (15 U.S.C. 16), without further notice to any party or other proceedings, if plaintiff has not withdrawn its consent, which it may do before the entry of the proposed Final Judgment by serving notice on defendants and filing that notice with the Court.

3. Defendants are bound by the provisions of the proposed Final Judgment before its approval by the Court and will take the following actions pursuant to this Stipulation:

a. Notify in writing, within 20 days of the filing of this Stipulation, each physician who has participated in Woman's Physician Hospital Organization (WPHO) that he or she is free at all times to communicate, negotiate, and contract independently from WPHO with any payer on any terms;

b. While forming or employing a messenger model or forming a qualified managed care plan before entry of the proposed Final Judgment: (1) provide a copy of the proposed Final Judgment to each owner or member of the organization forming the messenger or qualified managed care plan and to each physician potentially participating in the messenger model, and (2) require, as a condition precedent to each physician's ownership, membership or participation, the physician to affirm in writing that he or she has read and understands the proposed Final Judgment and agrees to be bound by it;

c. Notify in writing, within 20 days of the filing of this Stipulation, each payer with which WPHO then has a contract that the payer may cancel or renegotiate the contract and that each physician who has participated in WPHO is free at all times to communicate, negotiate, and contract on any terms with such payer independently from, and without consultation with, WPHO;

d. Notify in writing, before entry of the proposed Final Judgment, each payer when it initially discusses (i) using the services of a messenger that would be subject to the proposed Final Judgment or (ii) contracting with a qualified managed care plan that would be subject to the proposed Final Judgment, that each participating physician is free at all times to communicate, negotiate, and contract with such payer independently on any terms, without consultation with the messenger or qualified managed care plan; and

e. Distribute a copy of the proposed Final Judgment to all directors and officers of defendants within 20 days of the filing of this Stipulation.

4. Within 30 days after the filing of this Stipulation, each defendant shall provide to plaintiff a certified statement describing the notifications and distributions of the Final Judgment it made under paragraph 3 of this Stipulation.

5. Each defendant shall give plaintiff at least 30-days notice of any proposed (a) dissolution of that defendant, (b) sale or assignment of claims or assets of that defendant resulting in a successor person, or (c) change in corporate structure of that defendant that might affect its compliance obligations under the proposed Final Judgment.

6. If plaintiff withdraws its consent, or if the Court does not enter the proposed Final Judgment under the terms of the Stipulation, this Stipulation shall be of no effect whatsoever, and the making of this Stipulation shall be without prejudice to any party in this or in any other proceeding.

FOR PLAINTIFF UNITED STATES OF AMERICA:

Anne K. Bingaman,
Assistant Attorney General.

Joel I. Klein,
Deputy Assistant Attorney General.

Rebecca P. Dick,
Deputy Director, Office of Operations.

Gail Kursh,
Chief, Health Care Task Force.

Mark J. Botti, Steven Kramer, Pamela C. Girardi,
Attorneys, U.S. Department of Justice, Antitrust Division, Health Care Task Force, Room 450, Liberty Place Bldg., 325 7th Street, NW., Washington, DC 20530, (202) 307–0827.

FOR DEFENDANT WOMAN'S HOSPITAL FOUNDATION:

John J. Miles, Bruce R. Stewart,
Ober, Kaler, Grimes & Shriver, Fifth Floor, 1401 H Street, NW., Washington, DC 20005, (202) 326–5008.

FOR DEFENDANT WOMAN'S PHYSICIAN HEALTH ORGANIZATION:

Toby G. Singer,
Jones, Day, Reavis & Pogue, 1450 G Street, NW., Washington, DC 20005, (202) 879–4654.

John J. Miles.

United States District Court for the Middle District of Louisiana

In the matter of: United States of America, Plaintiff, vs. Woman's Hospital Foundation and Woman's Physician Health Organization, Defendants. Civil Action No: 96–389–B–M2; Filed: April 23, 1996.

Final Judgment

Plaintiff, the United States of America, having filed its Complaint on April 23, 1996, and plaintiff and defendants, by their respective attorneys, having consented to the entry of this Final Judgment without trial or adjudication of any issue of fact or law, and without this Final Judgment constituting any evidence against or an admission by any party regarding any issue of fact or law;

NOW, THEREFORE, before the taking of any testimony, and without trial or adjudication of any issue of fact or law, and upon consent of the parties, it is hereby ORDERED, ADJUDGED, AND DECREED:

I

Jurisdiction

This Court has jurisdiction over the subject matter and each of the parties to this action. The Complaint states claims upon which relief may be granted against the defendants under Sections 1 and 2 of the Sherman Act, 15 U.S.C. 1 and 2.

II

Definitions

As used in this Final Judgment:

(A) ''Competing physicians'' means solo practitioners or separate physician practice groups in the same relevant physician market.

(B) ''Consenting physician'' means physicians who have agreed, through implementation of Section V(B), to be bound by this Final Judgment.

(C) ''Messenger model'' means the use of an agent or third party (''the messenger'') to convey to payers any information obtained from participating physicians about the prices or other competitively sensitive terms and conditions each physician is willing to accept from any payer, and to convey to physicians any contract offer made by a payer, where:

(1) Pursuant to Section V(B), participating physicians have received actual notice of this Final Judgment and agreed in writing to be bound by it;

(2) The messenger informs each payer at the outset of the messenger's involvement with the payer that the payer may refuse to respond to offers conveyed by the messenger or may terminate involvement with the messenger at any time and that participating physicians are free at all times to communicate, negotiate and contract on any terms with the payer independently from, and without consultation with, the messenger;

(3) The messenger informs each participating physician when the physician first authorizes the messenger to carry messages to and from the physician and annually thereafter that the physician is free at all times to communicate, negotiate and contract on any terms with any payer independently from, and without consultation with, the messenger;

(4) The messenger does not communicate to participating physicians regarding, or comment on, a payer's refusal to use or decision to discontinue using the messenger's services, other than to inform participating physicians that a payer has decided not to use the messenger's services;

(5) The messenger conveys to participating physicians each and every offer that a payer delivers to the messenger unless (a) the offer is the payer's first offer and lacks material terms such that it could not be considered a bona fide offer, or (b) the messenger applies preexisting objective criteria, not involving prices or other competitively sensitive terms and conditions, in a nondiscriminatory manner (for example, refusing to convey offers of payers that refuse to pay a fee for conveying the offer, offers for plans that do not cover a certain minimum number of people, or offers made after the agent or messenger has conveyed a stated maximum number of offers for a given time period);

(6) All communications by the messenger to participating physicians (other than communications to physicians in their capacity as directors or officers of an organization employing the messenger model) regarding fees, payers and contracts are in writing or recorded, except that the messenger may communicate orally on these subjects when the communication pertains to ministerial matters or when an individual physician initiates the communication and a written record of the date of, participants to and subject matter of the conversation is kept by the messenger;

(7) Each participating physician agrees with the messenger not to discuss with competing physicians information on fees, contract terms and conditions, contract offers, or reactions to contract offers;

(8) Each competing, participating physician makes a separate, independent, and unilateral decision to accept or reject a payer's offer;

(9) Information on prices or other terms and conditions conveyed to payers is obtained by the messenger separately from each competing, participating physician;

(10) The messenger does not negotiate collectively for participating physicians, disseminate to any physician the messenger's or any other physician's views or intentions as to an offer, or otherwise serve to facilitate any agreement among competing physicians on prices or other terms and conditions;

(11) The messenger does not enter into contracts with payers unless, in executing contracts on behalf of any competing, participating physician, it acts consistently with the foregoing requirements of this Section II(C), no contract grants it the authority to cancel the contract prior to the stated term of the contract, and each competing physician makes separate, independent and unilateral decisions whether to cancel or renew contracts; and,

(12) The messenger maintains all documents received or created by it, relating to contracting, fees or physician participation, other than invoices, receipts and personnel records, for the duration of this Final Judgment.

As long as the messenger acts consistently with the foregoing, it may:

(1) Convey to a participating physician objective information about proposed contract terms, including comparisons with terms offered by other payers;

(2) Solicit clarifications from a payer of proposed contract terms, or engage in discussions with a payer regarding contract terms other than prices and other competitively sensitive terms and conditions;

(3) Convey to a participating physician any response made by a payer to information conveyed or clarifications sought;

(4) Convey to a payer the acceptance or rejection by a participating physician of any contract offer made by the payer; and,

(5) At the request of the payer, provide the individual response, information, or views of each participating provider concerning any contract offer made by such payer.

(D) ''Participating physicians'' means those physicians who own an interest in or authorize a qualified managed care plan to negotiate or contract on their behalf with payers, or who authorize a messenger to carry offers, acceptances and other messages between themselves and payers.

(E) ''Person'' means any natural person, corporation, firm, company, sole proprietorship, partnership, joint venture, association, institute, governmental unit, or other legal entity.

(F) ''Pre-existing physician practice group'' mean a physician practice group existing as of the date of the filing of the Complaint in this section. A pre-existing physician practice group may add any physician to the group after the filing of the Compliant, without losing the status of ''pre-existing'' under this definition for any relevant physician market, provided the physician was not offering services in the relevant physician market before joining the group and would not have entered that market but for the group's efforts to recruit the physician.

(G) ''Qualified managed care plan'' means an organization that is owned, in whole or in part, by either or both of the defendants, offers a provider panel and satisfies each of the following criteria:

(1) Its owners or not-for-profit members (''members'') who compete with other owners or members or with subcontracting physicians participating in the plan, (a) share substantial financial risk for the payment of services provided pursuant to contracts negotiated or executed by it and (b) in combination with the owners and members of all other physician networks in which Woman's Hospital, WPHO or any of them own an interest constitute no more than 30% of the physicians in any relevant physician market, except that it may include any single physician, or any single preexisting physician practice group for each relevant physician market, so long as Woman's Hospital, WPHO and they do not own an interest in another physician network;

(2) Its participating physicians include no more than 30% of the physicians in any relevant physician market unless, for those subcontracting physicians whose participation increases the panel beyond 30%, (a) there is a sufficient divergence of economic interest between such subcontracting physicians and the plan's owners or members to cause the owners or members to bargain down the fees of the subcontracting physicians because the extent of the owners' or members' profits under each payer contract depends directly on the fees

negotiated with the subcontracting physicians, (b) the contractual relationship between owners or members and such subcontracting physicians precludes a higher rate for subcontracting physicians resulting in the same or higher profits for owners or members, (c) the plan does not directly pass through to a payer liability for making payments to such subcontracting physicians, (d) a most-favored-nations clause or any similar term does not apply to the relationship between the plan and such subcontracting doctors, and (e) the plan does not compensate such subcontracting physicians in a manner that substantially replicates ownership in the organization;

(3) It does not facilitate agreements between competing physicians concerning charges, or other terms and conditions, relating to payers not contracting with the organization;

(4) Pursuant to Section V(B), its owners or members have received actual notice of this Final Judgment and agreed in writing to be bound by it; and

(5) It is not operated with the purpose or effect of maintaining or increasing physician fees.

The organization may at any given time exceed the 30% limitation as a result of any physician exiting any relevant physician market or the addition of any physician not previously offering services in a relevant physician market who would not have entered that market but for the organization's efforts to recruit the physician into the market; however, the organization may not exceed the 30% limitation by any greater degree than is directly caused by such exit or entry.

(H) ''Relevant market'' means, unless defendants obtain plaintiff's prior written approval of a different definition, physicians who regularly practice (a) in obstetrics or gynecology in the Baton Rouge area, or (b) services other than obstetric or gynecologic, in any other relevant market, as defined by federal antitrust principles.

(I) ''Substantial financial risk'' means financial risk achieved through capitation or the creation of significant financial incentives for the group to achieve specified cost-containment goals, such as withholding from all members a substantial amount of the compensation due to them, with distribution of that amount to the members or owners only if the cost-containment goals are met.

(J) ''Woman's Hospital'' means Woman's Hospital Foundation, each of its divisions, parents, subsidiaries, and affiliates, each other person directly or indirectly, wholly or in part, owned or controlled by it, and each partnership or joint venture to which any of them is a party, each of the foregoing person's successors, and all of their directors, officers, and employees.

(K) ''WPHO'' means Woman's Physician Health Organization, each of its successors, divisions, parents, subsidiaries, and affiliates, each other person directly or indirectly, wholly or in part, owned or controlled by it, and each partnership or joint venture to which any of them is a party, and all of their directors, officers, and employees.

III

Applicability

This Final Judgment applies to Woman's Hospital and WPHO, to all consenting physicians, and to all other persons who receive actual notice of this Final Judgment by personal service or otherwise and then act or participate in active concert with any or all of the defendants.

IV

Injunctive Relief

(A) Woman's Hospital and WPHO are enjoined from:

(1) Directly or through any agent, organization or other third party, expressing views on, or conveying information on, competing physicians' prices or other terms and conditions, or negotiating on behalf of competing physicians;

(2) Owning an interest in, contracting with, or controlling one or more organizations, including WPHO, in which individually or cumulatively participating physicians constitute more than 30% of the physicians in any relevant market;

(3) Owning an interest or participating in any organization that directly, or through any agent, organization or other third party, sets, expresses views on, or conveys information on prices or other terms and conditions for competing physicians' services, or negotiates for competing physicians unless the organization complies with paragraphs (2) through (6) of this Section IV(A) as if those paragraphs applied to that organization;

(4) Precluding or discouraging any physician from negotiating or contracting with any payer;

(5) Providing disincentives for, or agreeing with, any physician not to deal with competitors of Woman's Hospital or WPHO, provided that nothing in this Final Judgment prohibits Woman's Hospital from entering into exclusive contracts for anesthesiology, radiology, pathology, neonatalogy, and perinatalogy services to the extent reasonably necessary to assure quality of care at the Hospital;

(6) Disclosing to any physician any financial or other competitively sensitive business information about any competing physician, except as is reasonably necessary for the operation of a qualified managed care plan for which defendants have received prior written approval from the Department of Justice, provided that nothing in this Final Judgment shall prohibit the disclosure of information already generally available to the medical community or the public.

(B) Each consenting physician is enjoined from:

(1) Owning an interest or participating in any organization, connected in any way with Woman's Hospital or WPHO, that directly, or through any agent, organization or other third party, sets, expresses views on, or conveys information on prices or other terms and conditions, or negotiates on behalf of competing physicians, unless the organization complies with Section IV(A) of this Final Judgment as if that Section applied to that organization; and

(2) participating in or facilitating any agreement among competing physicians on fees or other terms and conditions for physician services, including the willingness of physicians to contract on any terms with particular payers or to use facilities competing with Woman's Hospital's facilities, unless the competing physicians share substantial financial risk and the agreement is ancillary to the shared risk; provided that nothing in this paragraph IV(B)(2) applies to the participation of competing physicians in any managed care plan or network of such a plan not owned or controlled by Woman's Hospital or WPHO.

(C) Woman's Hospital is enjoined from agreeing with any person affiliated directly or indirectly with any potential or actual competing facility to allocate or divide the market for, or set the price for, any service, including offering lower rates for inpatient services to any payer on the condition that the payer or any person affiliated with the payer not offer inpatient obstetrical services.

(D) Nothing in this Final Judgment prohibits the defendants or the consenting physicians from

(1) Forming, operating, owning an interest in, or participating in (a) a messenger model, or (b) a qualified managed care plan if defendants obtain prior written approval from the Department of Justice, which will not be withheld unreasonably; or

(2) Engaging in activity delineating in the attached Safety Zones of Statements

5 and 6 of the 1994 Statements of Enforcement Policy and Analytical Principles Relating to Health Care and Antitrust.

V

Additional Provisions

Woman's Hospital and WPHO shall:

(A) Notify in writing each WPHO participating physician, within ten days of entry of this Final Judgment (unless such notification has already been given) and annually thereafter during the term of this Final Judgment, that the physician is free at all times to communicate, negotiate or contract on any terms with any payer independently from, and without consultation with, WPHO;

(B) While forming or employing a messenger model or forming a qualified managed care plan, (1) provide a copy of the Final Judgment to each owner or member of the organization forming the messenger or qualified managed care plan and to each physician applying for participation in the messenger model, and (2) require, as a condition precedent to the physician's ownership or membership in the organization, or participation in a messenger model, the physician to affirm in writing that the physician has read and understands this Final Judgment and agrees to be bound by this Final Judgment;

(C) Notify in writing, within ten days of entry of this Final Judgment (unless such notification has already been given), each payer with which WPHO then has a contract that the payer may cancel the entire contract and that each physician who has participated in WPHO is free at all times to communicate, negotiate, and contract on any terms with such payer independently from, and without consultation with, WPHO;

(D) Notify in writing, within ten days of entry of this Final Judgment (unless such notification has already been given) each payer with which WPHO then has a contract, and during the term of this Final Judgment, each payer when it initially discusses using the services of a messenger subject to this Final Judgment or contracting with a qualified managed care plan subject to this Final Judgment, that each participating physician is free to communicate, negotiate or contract with such payer on any terms independently from, and without consultation with, the messenger or qualified managed care plan; and

(E) Notify, as applicable, the plaintiff at least 30 days prior to any proposed (1) dissolution of a defendant, (2) sale or assignment of claims or assets of a defendant resulting in a successor person, or (3) change in corporate structure of a defendant that may affect compliance obligations arising out of this Final Judgment.

VI

Compliance Program

Each defendant shall maintain a judgment compliance program, which shall include:

(A) Distributing within 60 days from the entry of this Final Judgment, a copy of the Final Judgment and Competitive Impact Statement to all directors and officers;

(B) Distributing in a timely manner a copy of the Final Judgment and Competitive Impact Statement to any person who succeeds to a position described in Paragraph VI(A);

(C) Briefing annually in writing or orally those persons designated in Paragraphs VI (A) and (B) on the meaning and requirements of this Final Judgment and the antitrust laws, including penalties for violation thereof;

(D) Obtaining from those persons designated in Paragraphs VI (A) and (B) annual written certifications that they (1) have read, understand, and agree to abide by this Final Judgment, (2) understand that their noncompliance with this Final Judgment may result in conviction for criminal contempt of court and imprisonment and/or fine, and (3) have reported violations, if any, of the this Final Judgment of which they are aware to counsel for the respective defendant; and

(E) Maintaining for inspection by plaintiff a record of recipients to whom this Final Judgment and Competitive Impact Statement have been distributed and from whom annual written certifications regarding this Final Judgment have been received.

VII

Certifications

(A) Within 75 days after entry of this Final Judgment, each defendant shall certify to plaintiff that it has given the notifications required by Section V and made the distribution of the Final Judgment and Competitive Impact Statement as required by Paragraph VI (A); and

(B) For 10 years after the entry of this Final Judgment, on or before its anniversary date, each defendant shall certify annually to plaintiff whether it has complied with the provisions of Sections V and VI applicable to it.

VIII

Plaintiff's Access

For the sole purpose of determining or securing compliance with this Final Judgment, and subject to any recognized privilege, authorized representatives of the United States Department of Justice, upon written request of the Assistant Attorney General in charge of the Antitrust Division, shall on reasonable notice be permitted:

(A) Access during regular business hours of any defendant to inspect and copy all records and documents in the possession or under the control of that defendant relating to any matters contained in this Final Judgment;

(B) To interview officers, directors, employees, and agents of any defendant, who may have counsel present, concerning such matters; and

(C) To obtain written reports from any defendant, under oath if requested, relating to any matters contained in this Final Judgment.

IX

Jurisdiction Retained

This Court retains jurisdiction to enable any of the parties to this Final Judgment to apply to this Court at any time for further orders and directions as may be necessary or appropriate to carry out or construe this Final Judgment, to modify or terminate any of its provisions, to enforce compliance, and to punish violations of its provisions.

X

Expiration of Final Judgment

This Final Judgment shall expire ten (10) years from the date of entry.

XI

Public Interest Determination

Entry of this Final Judgment is in the public interest.

Dated: _____.

_____

United States District Judge

United States District Court for the Middle District of Louisiana

In the matter of: United States of America, Plaintiff, vs. Woman's Hospital Foundation and Woman's Physician Health Organization, Defendants. Civil Action No: 96–389–BMZ.

Amended Competitive Impact Statement

Pursuant to Section 2(b) of the Antitrust Procedures and Penalties Act, 15 U.S.C. 16(b)–(h) (''APPA''), the United States files this Competitive Impact Statement relating to the proposed Final Judgment submitted for entry in this civil antitrust proceeding.

I

Nature and Purpose of the Proceeding

On April 23, 1996, the United States filed a civil antitrust complaint alleging that defendant Woman's Health Foundation (''WHF''), which owns and operates Woman's Hospital, and defendant Woman's Physician Health Organization (''WPHO''), with others not named as defendants, entered into an agreement and took other actions, the purpose and effect of which were, among other things, to reduce competition among obstetrician/gynecologists (''OB/GYNs'') and other doctors and prevent or delay the continued development of managed care in Baton Rouge, Louisiana (''Baton Rouge''), and to maintain willfully Woman's Hospital's monopoly in inpatient obstetric care, in violation of Sections 1 and 2 of the Sherman Act, 15 U.S.C. 1, 2. The Complaint seeks injunctive relief to enjoin continuance and recurrence of these violations.

The United States filed with the Complaint a proposed Final Judgment intended to resolve this matter. Entry of the proposed Final Judgment will terminate this action, except that the Court will retain jurisdiction over the matter to interpret, enforce, or modify the judgment, or punish violations of its provisions.

Plaintiff and both defendants have stipulated that the Court may enter the proposed Final Judgment after compliance with the APPA, unless prior to entry plaintiff has withdrawn its consent. The proposed Final Judgment provides that its entry does not constitute any evidence against, or admission by, any party concerning any issue of fact or law.

The present proceeding is designed to ensure full compliance with the public notice and other requirements of the APPA. In the Stipulation to the proposed Final Judgment, defendants have also agreed to be bound by the provisions of the proposed Final Judgment pending its entry by the Court and to take certain corrective actions.

II

Practices Giving Rise to the Alleged Violations

Woman's Hospital is the dominant provider of private inpatient obstetrical care in Baton Rouge. In the late 1980's, competition among doctors for participation in managed care plans created the opportunity for the entry of other Baton Rouge area hospitals into the market for inpatient obstetrical care. In 1991, General Health, Inc. (''General Health'') announced that it would build a hospital (the ''Health Center'') with 5 to 6 dedicated OB/GYN beds. Wonman's Hospital was particularly threatened by General Health's Center because General Health also owned Gulf South Health Plans, Inc. (''Gulf South''), the largest managed care plan in Baton Rouge. Once General Health's new facility achieved full-service status, Gulf South would have substantially more negotiating leverage with Woman's Hospital because Gulf South could employ the Health Center as a preferred hospital over Woman's Hospital in Gulf South's network.

Women's Hospital entered into negotiations with General Health and offered to continue contracting with Gulf South if General Health would agree to stay out of the obstetrical business in Baton Rouge for the next 5 to 7 years. Woman's Hospital eventually retreated from this attempt to foreclose the Health Center from offering inpatient obstetrical services and took alternative steps to achieve the same result.

Managed care plans could not use the Health Center's availability to obtain significant price concessions from Woman's Hospital, if Woman's Hospital could disrupt the competitive forces that would prompt the OB/GYNs on its medical staff to admit patients to the Health Center. Accordingly, in 1993, Woman's Hospital formed defendant WPHO, a physician-hospital organization, whose purpose at the time of formation was to establish a minimum physician fee schedule and serve as a joint bargaining agent on behalf of Woman's Hospital and these OB/GYNs. Woman's Hospital hoped to assure the continued ''loyalty'' of its OB/GYNs through WPHO.

WPHO developed a minimum fee schedule that listed fees for OB/GYNs that were substantially higher than the fees managed care plans were then paying OB/GYNs under individual contracts. Approximately 90% of the OB/GYNs delivering privately insured babies in the Baton Rouge area committed to WPHO after reviewing this fee schedule.

WPHO then signed contracts with a number of managed care plans, two of which were attempting to set up operations in the Baton Rouge area. Each of these new plans first attempted to contract directly with OB/GYNs independently of WPHO but was unsuccessful. In addition, Gulf South was forced to accept OB/GYNs on its panel with whom it had not previously contracted and to accept the WPHO fee schedule for all OB/GYNs in WPHO, which was significantly higher than the fee schedule Gulf South had previously applied to its participating physicians.

Based on the facts described above and those set forth more fully in the Complaint, the Complaint alleges that the defendants (1) entered into a contract, combination, or conspiracy that eliminated competition among physicians and reduced or limited the development of managed care plans in violation of Section 1 of the Sherman Act, 15 U.S.C. 1; and defendant Woman's Hospital (2) attempted to maintain its monopoly in inpatient obstetrical services, with the specific intent to do so, and (3) willfully maintained its monopoly in inpatient obstetrical services in violation of Section 2 of the Sherman Act, 15 U.S.C. 2.

III

Explanation of the Proposed Final Judgment

The proposed Final Judgment is intended to restore to Baton Rouge consumers of obstetrical services the benefits of competition among obstetrical providers that defendants have eliminated or prevented. At the same time, the proposed Final Judgment takes into account any benefits to consumers that Woman's Hospital and Woman's medical staff may offer through collective marketing of their services by permitting such collective action that is unlikely to reduce competition among the physicians or prevent competition between Woman's Hospital and other hospitals.

A. Scope of the Proposed Final Judgment

Section III of the proposed Final Judgment provides that the Final Judgment shall apply to defendants, to all ''consenting physicians,'' and to all other persons who receive actual notice of the proposed Final Judgment by personal service or otherwise and then participate in active concert with any defendant. The proposed Final Judgment applies to Woman's Hospital, WPHO, and all ''consenting physicians'' defined as physicians who remain or become owners or participants in physician networks owned or operated by Woman's Hospital or WPHO.

B. Prohibitions and Obligations

Sections IV and V of the proposed Final Judgment contain the substantive provisions of the Judgment.

In Section IV(A), Woman's Hospital and WPHO are enjoined from setting, negotiating, or expressing views on, prices or other competitive terms and conditions, for competing physicians.

Women's Hospital and WPHO are further enjoined from owning an interest in, contracting, with, or controlling any organization in which participating physicians constitute more than 30% of the physicians in any relevant market. Section IV(D), however, permits Woman's Hospital and WPHO to use a messenger model, and, provided they obtain the prior written approval of the Department of Justice, to form and operate a Qualified Managed Care Plan (''QMCP'')—as defined in the proposed Final Judgment and discussed below. Section IV(A) also prohibits Woman's Hospital and WPHO from precluding or discouraging any physician from contracting with any payer, or providing incentives for, or agreeing with, any physician not to deal with competitors of Woman's Hospital or WPHO. Nothing in Section IV(A), however, prohibits Woman's Hospital from entering into exclusive contracts for anesthesiology, radiology, pathology, neonatalogy, and perinatalogy services to the extent reasonably necessary to assure quality of care at the Hospital.

In addition, Section IV(A) enjoins Woman's Hospital and WPHO from disclosing to any physician financial or other competitively sensitive business information about any competing physicians. An exception permits disclosure of such information if reasonably necessary for the operation of an approved QMCP, or if the information is already generally available to the medical community or the public. Section IV(C) also permits the exchange of information pursuant to the Antitrust Safety Zones delineated in Statements 5 and 6 of the 1994 Statements of Enforcement Policy and Analytical Principles Relating to Health Care and Antitrust (''Health Care Policy Statements'').[1]

Section IV(B) enjoins each ''consenting physician'' from owning an interest or participating in any organization, connected in any way with Woman's Hospital or WPHO, that directly or through any agent, organization or other third party, sets, expresses views on, or conveys information on prices or other terms and conditions, or negotiatees for competing physicians, unless that organization complies with Section IV(A). Section IV(B) further enjoins ''consenting physicians'' from participating in or facilitating any agreement among competing physicians on fees or other terms and conditions for physician services, including the willingness of physicians to contract on any terms with particular payers, or to use facilities competing with Woman's Hospital's facilities, unless the competing physicians share substantial financial risk and and the agreement is ancillary to the shared risk. However, noting in Section IV(B) applies to the participation of competing physicians in any managed care plan or network of such plan not owned or controlled by Woman's Hospital or WPHO.

Section IV(C) enjoins Woman's Hospital from agreeing with any person affiliated directly or indirectly with any potential or actual competing facility or allocate or divide the market, or set the price, for any service, including offering lower rates for inpatient services to any payer on the condition that the payer or any person affiliated with the payer not offer inpatient obstetrical services.

Section V of the proposed Final Judgment contains additional provisions regarding Woman's Hospital and WPHO. Section V(A) requires Woman's Hospital and WPHO to notify in writing participating physicians annually that they are free to communicate, negotiate or contract on any terms with any payer independently from, and without consultation with, WPHO. Similarly, Sections V(C) and V(D) require Women's Hospital and WPHO to notify in writing each payer with whom WPHO has a contract, and during the term of the Final Judgment, each payer when it initially discusses using the services of a messenger or contracting with a QMCP subject to this Final Judgment, that each participating physician is free to communicate, negotiate or contract with such payer on any terms independently from, and without consultation with, WPHO, the messenger, or the QMCP.

Under Section V(B), Woman's Hospital and WPHO are required to, while forming or employing a messenger model or forming a QMCP, (1) provide a copy of the Final Judgment to each owner or member of the organization forming the messenger or QMCP and to each physician applying for participation in the messenger model, and (2) require as a condition precedent to the physician's ownership or membership in the organization, or participation in a messenger model, the physician to affirm in writing that the physician has read and understands the Final Judgment and agrees to be bound by it.

Section V(E) provides that each defendant must notify the Antitrust Division of the United States Department of Justice of any proposed change in corporate structure at least 30 days before that change to the extent the change may affect compliance obligations arising out of the proposed Final Judgment.

Section VI of the proposed Final Judgment requires defendants to implement a judgment compliance program. Section VI(A) requires that within 60 days of entry of the Final Judgment, defendants must provide a copy of the proposed Final Judgment and the Competitive Impact Statement to all directors and officers. Sections VI (B) and (C) require defendants to provide a copy of the proposed Final Judgment and Competitive Impact Statement to persons who assume those positions in the future and to brief such persons annually on the meaning and requirements of the proposed Final Judgment and the antitrust laws, including penalties for violating them. Section VI(D) requires defendants to maintain records of such persons' annual written certifications indicating that they (1) have read, understand, and agree to abide by the terms of the proposed Final Judgment, (2) understand that their noncompliance with the proposed Final Judgment may result in conviction for criminal contempt of court, and imprisonment, and/or fine, and (3) have reported any violation of the proposed Final Judgment of which they are aware to counsel for defendants. Section VI(E) requires defendants to maintain for inspection by the Antitrust Division a record of recipients to whom the proposed Final Judgment and Competitive Impact Statement have been distributed and from whom annual written certifications regarding the proposed Final Judgment have been received.

The proposed Final Judgment also contains provisions in Section VII requiring defendants to certify their compliance with specified obligations of Section VI(A) of the proposed Final Judgment. Section VIII of the proposed Final Judgment sets forth a series of measures by which the Antitrust Division may have access to information needed to determine or secure defendants' compliance with the proposed Final Judgment.

Finally, Section X states that the Judgment expires ten years from the date of entry.

C. Effect of the Proposed Final Judgment on Competition

The proposed Final Judgment remedies, and prevents recurrence of, violations of Sections 1 and 2 of the Sherman Act. Defendant Woman's Hospital violated Section 2 by attempting to maintain and maintaining its monopoly in inpatient obstetrical services. Woman's Hospital and WPHO

[1] 4 Trade Reg. Rep. (CCH) ¶ 13,152 at 20,782, 20,784.

violated Section 1 by entering into an agreement with OB/GYNs on Woman's Hospital's medical staff that unreasonably restrained competition among the OB/GYNs and prevented significant competition from developing in the market for inpatient obstetrical services.

1. Competition for Inpatient Obstetric Services

Woman's Hospital violated Section 2 by depriving Baton Rouge health care consumers of the significant benefits from competition for inpatient obstetric business between Woman's Hospital and General Health's Health Center. Some competition started to develop with the entry of General Health and another Baton Rouge hospital, causing Woman's Hospital to waive direct payments by women who expressed a desire to deliver at one of the competing facilities. Woman's Hospital, in the minutes of the first meeting of its Strategic Planning Committee in 1994, articulated its concern that competition from General Health might cause more significant competition in the form of ''deep discounting'' of the rates charged to managed care plans for deliveries.

In response to that concern, Woman's Hospital tried to prevent the development of competing obstetric facilities in Baton Rouge. Woman's Hospital attempted first to prevent General Health from entering the market by offering to continue contracting with Gulf South, General Health's wholly owned managed care plan, if General Health did not enter the market. Though General Health ultimately did not accept Woman's Hospital's offer, Woman's Hospital could realistically seek the same type of agreement in the future. Woman's Hospital and General Health have an ongoing relationship through Woman's participation in the Gulf South provider network and both Woman's Hospital and General Health might find it in their mutual self interest to eliminate competition in inpatient obstetrics. Accordingly, Section IV(C) of the proposed Final Judgment prohibits Woman's Hospital from pursuing this type of anticompetitive conduct in the future.

Woman's Hospital succeeded in preventing the development of inpatient obstetrical competition through the formation of WPHO. By organizing WPHO, Woman's Hospital created a vehicle for the OB/GYNs on its medical staff to wield market power. Creation of market power for such a group of physicians would not normally further a hospital's interests and could, in some circumstances, work against its interests. Accordingly, Woman's Hospital would not have organized the physicians toward this end, absent Woman's interest in preventing the development of inpatient obstetrical competition.

Woman's Hospital's organization of WPHO furthered this interest of Woman's Hospital by substantially limiting the ability of managed care plans to steer patients to General Health's facility. Managed care plans had successfully selectively contracted with OB/GYNs in the competitive market that existed before the formation of WPHO. The formation of WPHO deprived plans of the opportunity to use competition among the OB/GYNs to induce the OB/GYNs to admit patients to General Health's facility. The proposed Final Judgment, as discussed in the next section, restores the competitive market by preventing price fixing by physicians or their exercise of market power.

2. Competition Among OB/GYNs and Other Physicians

The agreement among Woman's Hospital, WPHO and the WPHO OB/GYNs unreasonably restrained competition among the OB/GYNs and competition among hospitals for inpatient obstetrical business. The agreement constitutes a *per se* violation of Section 1 because of its naked purpose and effect of reducing price competition among the OB/GYNs. The agreement's reduction of competition among the OB/GYNs and among hospitals, without any substantial offsetting benefit, establishes a violation of Section 1 under the rule of reason, as well.

a. The Contract, Combination or Conspiracy in Restraint of Trade

The full scope of the unlawful conspiracy charged in this case is not confined to the four corners of the documents incorporating WPHO or signed by Woman's Hospital and members of its medical staff. Rather, the facts alleged in the Complaint establish a broader understanding among competing OB/GYNs to restrain price competition among themselves by contracting either through WPHO at or above the minimum WPHO fee schedule or individually on the same basis.[2]

Woman's Hospital orchestrated the formation of WPHO through a number of general meetings with its medical staff, including the OB/GYNs. The Hospital solicited the OB/GYNs' preliminary commitment to WPHO and their final agreement to the fee schedule through memoranda addressed to all members of the medical staff.

The proposal to form WPHO necessarily carried with it the understanding that a substantial percentage, if not all, of the OB/GYNs would present a united front to managed care plans and other payers on terms established through WPHO. Each OB/GYN's agreement to permit WPHO to negotiate on that doctor's behalf would have been useless at best, or actually harmful, to the doctor without an understanding that most would not contract independently of WPHO at rates below WPHO's minimum fee schedule. WPHO was proposing a broader panel and higher fees than managed care plans had already obtained through individual contracts with OB/GYNs. Neither Woman's Hospital nor the OB/GYNs could realistically have believed that the plans would have agreed with WPHO to increase fees to OB/GYNs and include additional OB/GYNs in their panels absent an understanding that the physicians would not continue to contract individually at competitive rates.

Participating OB/GYNs had substantial reasons to expect that WPHO would further their understanding to eliminate price competition. Their interest in not competing with each other was aligned with Woman's Hospital's interest in not competing with the Health Center. Woman's Hospital and the OB/GYNs appointed 12 of the 14 Directors to WPHO's Board of Directors, thus assuring that WPHO would pursue higher OB/GYN fees and resist contractual terms that could induce the OB/GYNs to make use of General Health's new inpatient obstetric facility.

Knowing that concerted action was contemplated and invited, each OB/GYN gave adherence to WPHO and participated in it. Each OB/GYN was well aware that others were asked to participate; each knew that cooperation was essential to successful operation of WPHO; each knew that WPHO, if successful, would result in an elimination of competition among OB/GYNs; and knowing that, each committed to WPHO and authorized WPHO to contract on their behalf.[3] In

[2] The existence of this agreement made it unnecessary for the Department to resolve whether physician representation on the board of WPHO, physician influence over Woman's Hospital, or other factors established that competing doctors controlled the establishment of their fees through WPHO and thus established an agreement among those competitors.

[3] WPHO strengthened the ability of the OB/GYNs to police the agreement among themselves. There was little likelihood that any substantial number of the approximately 45 OB/GYNs who joined WPHO

short, an agreement among OB/GYNs to restrain price competition among themselves is shown by the nature of the market for OB/GYNs' services existing before formation of WPHO, the purposes for which WPHO was formed, and the manner in which it was formed. *See Interstate Circuit, Inc.* v. *United States*, 306 U.S. 208, 226–27 (1939); *In re Chain Pharmacy Ass'n of New York, Inc.*, No. 9227, slip op. at 70–71 (FTC Initial Decision, filed May 17, 1991).

The agreement among Woman's Hospital, WPHO, and the WPHO OB/GYNs to limit price competition among OB/GYNs was *per se* unlawful.[4] WPHO did not develop utilization review standards, and the agreement to limit price competition was not reasonably necessary to further any efforts by WPHO to encourage physicians to practice more cost-effectively. No legitimate argument exists, in this case, therefore, that the collective pricing of OB/GYNs' services here was ancillary to any procompetitive activity.

Defendants and WPHO physicians collectively obtained higher fees for OB/GYNs, deprived managed care plans of the ability to selectively contract with OB/GYNs, and prevented the development of competition for inpatient obstetrical services. These anticompetitive effects were not offset by any procompetitive effect. Thus, even under a rule of reason analysis, defendants violated Section 1 of the Sherman Act.

As discussed above, Sections IV (A) and (B) of the proposed Final Judgment prevent the continuation or recurrence of defendants' price fixing activity and exercise of market power by enjoining Woman's Hospital and WPHO from, directly or indirectly, negotiating or setting prices or other competitive terms and conditions for competing physicians and from disclosing financial or other competitively sensitive information about competing physicians. The requirements of the proposed Final Judgment should restore and protect competition among physicians and permit the development of competition for inpatient obstetrical services in Baton Rouge.

b. Permitted Conduct

Section IV(D) of the Judgment describes two circumstances in which WPHO or similar organizations subject to the Judgment may participate in the contracting activities of competing physicians: first, by using a ''messenger model,'' a term defined in the proposed Final Judgment; second, by obtaining approval from the Department of Justice to own and operate a QMCP.

i. The Messenger Model

The proposed Final Judgment permits WPHO to use an agent or third party to facilitate the transfer of information concerning prices and other competitively sensitive information between individual physicians and purchasers of physician services.[5] Appropriately designed and administered, such messenger models rarely present substantial competitive concerns and indeed have the potential to reduce the transaction costs of negotiations between health plans and numerous physicians.

The proposed Final Judgment makes clear that the critical feature of a properly devised and operated messenger model is the individual providers make their own separate decisions about whether to accept or reject a purchaser's proposal, independent of other physicians' decisions and without any influence by the messenger (Section II(C)) The messenger may not, under the proposed Judgment, coordinate individual providers' responses to a particular proposal, disseminate to physicians the messenger's or other physicians' views or intentions concerning the proposal, act as an agent for collective negotiation and agreement, or otherwise serve to facilitate collusive behavior.[6] The proper role of messenger is simply to facilitate the transfer of information between purchasers of physician services and individual physicians or physician group practices and not to coordinate or otherwise influence the physicians' decision-making processes.[7]

ii. The Qualified Managed Care Plan

The proposed Final Judgment provides defendants with the opportunity to seek approval from the Department of Justice to operate a QMCP. The requirement of prior approval by the Department was necessary for several reasons. First, because a QMCP, in contrast with a messenger model, allows for some collective decision-making among competitors, the Department must look carefully at the potential for a QMCP to result in anticompetitive behavior. In this case, the Department was particularly concerned that past behavior indicated a potential for physician boycott of new entrants into the inpatient obstetrics market. Indeed, managed care plans have been deprived of benefits of competition in the market for inpatient obstetrical services because OB/GYNs have refused to deliver at the Health Center. In addition, the Department perceived there to be a greater potential for abuse of a QMCP operated by a single specialty with very closely aligned interests. Finally, there was no indication that the operation of a QMCP by defendants in this case would have any pro-competitive benefits. Specifically, Woman's Hospital and WPHO did not indicate that their motivation for operating a QMCP was to offer their community a locally owned and operated managed care plan, a factor that has been an important consideration for the Department in permitting the operation of QMCPs in other communities.[8] In reviewing a request from defendants for approval to operate a QMCP, the Department will consider the totality of circumstances in light of the concerns discussed above. The proposed Final Judgment provides that the Department's approval will not

could secretly break ranks. Woman's Hospital's monopoly in inpatient obstetrics assured Woman's Hospital knowledge of the identity of managed care plans operating in Baton Rouge and of the OB/GYNs in the networks of those plans. WPHO would thus readily detect any OB/GYN who contracted outside of WPHO at lower rates. Under these circumstances, the agreement of the OB/GYNs did, and was likely to, lead to real anticompetitive harm.

[4] The agreement does not escape condemnation simply because WPHO appointed a consultant and a committee of nonphysicians to determine the fee schedule. The procedure employed by WPHO here is sharply distinguishable from a properly structured messenger model, discussed *infra* and permitted under the proposed Final Judgment. Here, a single agent was used precisely to fix fees to be charged to managed care plans by all of WPHO's member doctors, not simply to convey information.

[5] ''Other competitively sensitive terms and conditions'' includes, for example, contractual terms concerning utilization review and quality assurance issues.

[6] For example, it would be a violation of the proposed Final Judgment if the messenger were to select a fee for a particular procedure from a range of fees previously authorized by the individual physician, or if the messenger were to convey collective price offers from physicians to purchasers or negotiate collective agreements with purchasers on behalf of physicians. This would be so even if individual physicians were given the opportunity to ''opt in'' or to ''opt out'' of any agreement. In each instance, it would in fact be the messenger, not the individual physician, who would be making the critical decision, and the purchaser would be faced with the prospect of a collective response.

[7] For Example, the messenger may convey to a physician objective or empirical information about proposed contract terms, convey to a purchaser any individual physician's acceptance or rejection of a contract offer, canvass member physicians for the rates at which each would be willing to contract even before a purchaser's offer is made, and charge a reasonable, non-discriminatory fee for messenger services. The proposal Final Judgment gives guidelines for these and other activities that a messenger may undertake without violating the Final Judgment. (Section II(C)).

[8] *See United States* v. *Health Care Partners, Inc.*, 60 Fed. Reg. 52014 (October 4, 1995) (Competitive Impact Statement); *United States* v. *Health Choice of Missouri, Inc.*, 60 Fed. Reg. 51808 (October 3, 1995) (Competitive Impact Statement).

be withheld unreasonably. (Section IV(D)(I)).

To comply with the requirements of a QMCP set forth in the proposed Final Judgment, (1) the owners or members of WPHO (to the extent they compete with other owners or members or compete with physicians on their provider panels) must share substantial financial risk, and constitute no more than 30% of the physicians in any relevant market;[9] *and* (2) to the extent WPHO has a provider panel that exceeds this limit in any relevant market, there must be a divergence of economic interest between the owners and the subcontracting physicians, such that the owners have the incentive to bargain down the fees of the subcontracting physicians.[10] (Section II(G) (1) and (2)) In addition, a QMCP cannot facilitate agreements between competing physicians concerning charges, or other terms and conditions relating to payers not contracting with the organization, and cannot be operated with the purpose or effect of maintaining or increasing physician fees. (Section II(G) (3) and (5)) The requirements of a QMCP are necessary to avoid the creation of a physician cartel while at the same time allowing payers access to provider-controlled plans.

3. Applicability to Consenting Physicians

The proposed Final Judgment applies not only to named defendants Woman's Hospital and WPHO, but also to all ''consenting physicians'' defined as physicians who continue as owners or participants in physician networks owned or operated by Woman's Hospital or WPHO. Consenting physicians are required to affirm in writing that the physician has read and understands the Final Judgment and agrees to be bound by it. (Section IV(B)).

Application of the proposed Final Judgment to consenting physicians will help prevent recurrence of the violations alleged in the Complaint. Those violations could not have occurred without the willing participation of physicians who, in addition to Woman's Hospital, were the intended beneficiaries of those violations. Physicians could abuse the messenger model and the QMCP in ways that might not violate the Final Judgment but would at the same time achieve the anticompetitive results addressed by the Final Judgment. The ''consenting physicians'' provisions should reduce this risk.

IV

Alternative to the Proposed Final Judgment

The alternative to the proposed Final Judgment would be a full trial on the merits of the case. In the view of the Department of Justice, such a trial would involve substantial costs to the United States and defendants and is not warranted because the proposed Final Judgment provides all of the relief necessary to remedy the violations of the Sherman Act alleged in the Complaint.

V

Remedies Available to Private Litigants

Section 4 of the Clayton Act, 15 U.S.C. 15, provides that any person who has been injured as a result of conduct prohibited by the antitrust laws may bring suit in federal court to recover three times the damages suffered, as well as costs and a reasonable attorney's fee. Entry of the proposed Final Judgment will neither impair nor assist in the bringing of such actions. Under the provisions of Section 5(a) of the Clayton Act, 15 U.S.C. 16(a), the proposed Final Judgment has no *prima facie* effect in any subsequent lawsuits that may be brought against one or more defendants in this matter.

VI

Procedures Available for Modification of the Proposed Final Judgment

As provided by Sections 2 (b) and (d) of the APPA, 15 U.S.C. 16 (b) and (d), any person believing that the proposed Final Judgment should be modified may submit written comments to Gail Kursh, Chief; Health Care Task Force; United States Department of Justice; Antitrust Division; 325 7th Street, NW., Room 400; Washington, DC 20530, within the 60-day period provided by the Act. Comments received, and the Government's responses to them, will be filed with the Court and published in the Federal Register. All comments will be given due consideration by the Department of Justice, which remains free, pursuant to Paragraph 2 of the Stipulation, to withdraw its consent to the proposed Final Judgment at any time before its entry, if the Department should determine that some modification of the Final Judgment is necessary for the public interest. Moreover, the proposed Final Judgment provides in Section IX that the Court will retain jurisdiction over this action, and that the parties may apply to the Court for such orders as may be necessary or appropriate for the modification, interpretation, or enforcement of the proposed Final Judgment.

VII

Determinative Documents

No materials and documents of the type described in Section 2(b) of the APPA, 15 U.S.C. 16(b), were considered in formulating the proposed Final Judgment. Consequently, none are filed herewith.

Dated: April 23, 1996.

Respectfully submitted,

Mark J. Botti,
Steven Kramer,
Pamela C. Girardi,
Attorneys, Antitrust Division, U.S. Dept. of Justice, 325 7th Street, N.W., Room 450, Washington, D.C. 20530, (202) 307–0827.

L.J. Hymel,
United States Attorney.

By: _____
John J. Gaupp,
LBN# 14976, Assistant United States Attorney, 777 Florida St., Suite 208, Baton Rouge, LA 70801, (504) 389–0443, Local Counsel.

[FR Doc. 96–11796 Filed 5–9–96; 8:45 am]

BILLING CODE 4410–01–M

[9] The financial risk-sharing requirement of a QMCP ensures that the physician owners in the venture share a clear economic incentive to achieve substantial cost savings and provide better services at lower prices to consumers. The 30% limitation is designed to ensure that there are available sufficient remaining physicians in the market with the incentive to contract with competing managed care plans or to form their own plans. These limitations are particularly critical in this case in view of defendants' prior conduct in forming negotiating groups with nearly every OB/GYN practicing at private hospitals in Baton Rouge and obtaining higher prices for these doctors.

[10] The QMCP's subcontracting requirements are designed to permit physician panels above the 30% limit, but with sufficient safeguards to avoid the risk of competitive harm. Specifically, the owners of a QMCP must bear significant financial risk for the payments to, and utilization practices of, the panel physicians in excess of the 30% limitation. In this way, a QMCP must operate with the same incentives as a nonprovider-controlled plan to bargain down the fees of the subcontracting physicians, and the risk of it using the subcontracts as a mechanism for increasing fees for physician services is substantially reduced.

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Advanced Telecommunications Information Distribution Research Consortium

Notice is hereby given that, on January 29, 1996, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. § 4301 *et seq.* (''the Act''), the Advanced Telecommunications information Distribution Research Consortium (''ATIRP Consortium'') has filed written notifications simultaneously with the Attorney General and the Federal Trade

Commission disclosing (1) the identities of the parties and (2) the nature and objectives of the venture. The notifications were filed for the purpose of invoking the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Pursuant to Section 6(b) of the Act, the identities of the parties are the United States of America, represented by U.S. Army Research Laboratories (''ARL''), Adelphi, MD; Sanders, a Lockheed Martin Company, Nashua, NH; Bell Communications Research, Inc., Morristown, NJ; City University of New York, City College, New York, NY; University of Delaware, Newark, DE; GTE Laboratories, Inc., Waltham, MA; Howard University, Washington, DC; University of Maryland, College Park, MD; Massachusetts Institute of Technology, Cambridge, MA; Morgan State University, Baltimore, MD; and Motorola, Inc., Scottsdale, AZ.

The nature of the ATIRP Consortium is to conduct research in the area of telecommunications and information distribution for a limited duration to gain further knowledge and understanding of emerging technologies. Through its partnerships, the Consortium will forge cooperative relationships with the customer community to develop innovative ideas and applications for new telecommunications and information distribution technologies.

Constance K. Robinson,

Director of Operations, Antitrust Division.

[FR Doc. 96–11652 Filed 5–9–96; 8:45 am]

BILLING CODE 4410–01–M

Drug Enforcement Administration

Manufacturer of Controlled Substances Notice of Registration; Norac Co., Inc.

By Notice dated October 16, 1995, and published in the Federal Register on October 23, 1995, (60 FR 54387), Norac Company, Inc., 405 S. Motor Avenue, Azusa, California 91702, made application to the Drug Enforcement Administration to be registered as a bulk manufacturer of tetrahydrocannabinols (7370), a basic class of controlled substance listed in Schedule I.

No comments or objections have been received. DEA has considered the factors in Title 21, United States Code, section 823(a) and determined that the registration of Norac Company, Inc. to manufacture the listed controlled substance is consistent with the public interest at this time. Therefore, pursuant to 21 U.S.C. 823 and 28 CFR 0.100 and 0.104, the Deputy Assistant Administrator, Office of Diversion Control, hereby orders that the application submitted by the above firm for registration as a bulk manufacturer of the basic class of controlled substance listed above is granted.

Dated: April 12, 1996.

Gene R. Haislip,

Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration.

[FR Doc. 96–11665 Filed 5–9–96; 8:45 am]

BILLING CODE 4410–09–M

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Review; Comment Request

May 6, 1996.

The Department of Labor (DOL) has submitted the following public information collection request (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (P.L. 104–13, 44 U.S.C. Chapter 35). A copy of this individual ICR, with applicable supporting documentation, may be obtained by calling the Department of Labor Acting Departmental Clearance Officer, Theresa M. O'Malley ((202) 219–5095). Individuals who use a telecommunications device for the deaf (TTY/TDD) may call (202) 219–4720 between 1:00 p.m. and 4:00 p.m. Eastern time, Monday through Friday.

Comments should be sent to the Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for the Employment and Training Administration, Office of Management and Budget, Room 10235, Washington, DC 20503 ((202) 395–7316), within 30 days from the date of this publication in the Federal Register.

The OMB is particularly interested in comments which:

* Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

* Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

* Enhance the quality, utility, and clarity of the information to be collected; and

* Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Agency: Employment and Training Administration.

Title: Job Search Assistance Demonstration Followup Interview.

Frequency: One-time survey.

Affected Public: Individuals or households.

Number of Respondents: 4,500.

Estimated Time Per Respondent: 30 minutes.

Total Burden Hours: 2,250.

Total Annualized capital/startup costs: 0.

Total Annual Costs (operating/maintaining systems or purchasing services): 0.

Description: The information collected in this questionnaire is necessary for the evaluation of the Job Search Assistance (JSA) demonstration, a Congressionally mandated demonstration and evaluation. The questionnaire collects information on employment and training services received and labor market experiences of unemployment insurance claimants selected for the demonstration.

Theresa M. O'Malley,

Acting Departmental Clearance Officer.

[FR Doc. 96–11765 Filed 5–9–96; 8:45 am]

BILLING CODE 4510–30–M

Office of the Assistant Secretary for Administration and Management

National Skill Standards Board; Notice of Open Meeting

AGENCY: Office of the Assistant Secretary for Administration and Management, Labor.

ACTION: Notice of open meeting.

SUMMARY: The National Skill Students Board was established by an Act of Congress, the Goals 2000: Educate America Act of 1994, Title V, Pub L. 103–227. The 27-member National Skill Standards Board will serve as a catalyst and be responsible for the development and implementation of a national system of voluntary skill standards and certification through voluntary partnerships which have the full and balanced participation of business, industry, labor, education and other key groups.

Time and Place: The meeting will be held from 8:00 a.m. to appproximately 11:30 a.m. on Friday, May 31, 1996, in the Mt. Vernon Salon A & B, 2nd Floor of the Madison Hotel at 15th & M Streets N.W, Washington, D.C.

Agenda: The agenda for the Board Meeting will include discussion of: Reports about NSSB focus groups and public hearings, and a panel discussion of the Palisades Education Summit.

Public Participation: The meeting from 8:00 a.m. to 11:30 a.m., is open to the public. Seating is limited and will be available on a first-come, first-served basis. Seats will be reserved for the media. Disabled individuals should contact Claire Grenewald at (202) 254–8628, if special accommodations are needed.

For Further Information Contact: Sally Conway, NSSB Outreach Director, at (202) 254–8628.

Signed at Washington, D.C., this 6th day of May 1996.

Judy Gray,

Executive Director, National Skill Standards Board.

[FR Doc. 96–11767 Filed 5–9–96; 8:45 am]

BILLING CODE 4510–23–M

Employment Standards Administration

Proposed Collection; Comment Request

ACTION: Notice.

SUMMARY: The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden, conducts a preclearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95) (44 U.S.C. 3506(c)(2)(A)). This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed. Currently, the Employment Standards Administration is soliciting comments concerning the proposed revision collection of OFCCP Recordkeeping/Reporting: Construction.

A copy of the proposed information collection request can be obtained by contacting the office listed below in the addressee section of this notice.

DATES: Written comments must be submitted to the office listed in the addressee section below on or before July 15, 1996. The Department of Labor is particularly interested in comments which:

* Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

* Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

* Enhance the quality, utility and clarity of the information to be collected; and

* Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submissions of responses.

ADDRESSES: Ms. Patricia A. Forkel, U.S. Department of Labor, 200 Constitution Ave., NW., Room S–3201, Washington, DC 20210, telephone (202) 219–7601 (this is not a toll-free number), fax 202–219–6592.

SUPPLEMENTARY INFORMATION:

I. Background

The Office of Federal Contract Compliance Programs enforces E.O. 11246, which prohibits employment discrimination because of race, color, religion, sex, or national origin, and requires affirmative action to ensure that persons are treated without regard to these prohibited factors. The Order applies to Federal contractors and subcontractors and to federally assisted construction contractors who have contracts exceeding $10,000. In addition, OFCCP enforces Section 503 of the Rehabilitation Act of 1973 which applies to Federal contractors and subcontractors with a contract exceeding $10,000, and the Vietnam Era Veterans' Readjustment Assistance Act of 1974, which applies to Federal contractors and subcontractors with a contract of $10,000 or more.

II. Current Actions

The Department of Labor seeks to revise this information collection. This revision is the result of the Program's decision to eliminate the routine submission of Form CC–257, which collects race and gender information on construction employees, classified by trade. The program has also reevaluated the burden effect of existing recordkeeping responsibilities, which results in a small increase in recordkeeping hours.

Type of Review: Revision.

Agency: Employment Standards Administration.

Title: OFCCP Recordkeeping/Reporting: Construction.

OMB Number: 1215–0163.

Affected Public: Businesses or other for-profit; Not-for-Profit Institutions, Small businesses or organizations.

Total Recordkeepers: 100,000.

Total Reporting Responses: 1,303.

Respondents	Average hours per response	Frequency	Total responses	Subtotal hours
Recordkeeping:				
100,000	48	Rcdkpg	100,000	4,800,000
(2,061 of above, Affirmative Action Plan)	15.107	Rcdkpg	2,061	31,136
Reporting:				
(1,283 of above, Compliance Reviews)	3	Annually	1,283	3,849
5 (Hometown Plans)	.42	Quarterly	20	8

Total Hours: 4,834,993.

Total Burden Cost (capital/startup): $0.

Total Burden Cost (operating/maintenance): $7.00.

Comments submitted in response to this notice will be summarized and/or included in the request for Office of management and Budget approval of the information collection request; they will also become a matter of public record.

Dated: May 6, 1996.

Cecily A. Rayburn,

Director, Division of Financial Management, Office of Management, Administration and Planning, Employment Standards Administration.

[FR Doc. 96–11764 Filed 5–9–96; 8:45 am]

BILLING CODE 4510–27–M

Pension and Welfare Benefits Administration

[Prohibited Transaction Exemption 96–34; Exemption Application No. D–09880, et al.]

Grant of Individual Exemptions; General Electric

AGENCY: Pension and Welfare Benefits Administration, Labor.

ACTION: Grant of individual exemptions.

SUMMARY: This document contains exemptions issued by the Department of Labor (the Department) from certain of the prohibited transaction restrictions of the Employee Retirement Income Security Act of 1974 (the Act) and/or the Internal Revenue Code of 1986 (the Code).

Notices were published in the Federal Register of the pendency before the Department of proposals to grant such exemptions. The notices set forth a summary of facts and representations contained in each application for exemption and referred interested persons to the respective applications for a complete statement of the facts and representations. The applications have been available for public inspection at the Department in Washington, D.C. The notices also invited interested persons to submit comments on the requested exemptions to the Department. In addition the notices stated that any interested person might submit a written request that a public hearing be held (where appropriate). The applicants have represented that they have complied with the requirements of the notification to interested persons. No public comments and no requests for a hearing, unless otherwise stated, were received by the Department.

The notices of proposed exemption were issued and the exemptions are being granted solely by the Department because, effective December 31, 1978, section 102 of Reorganization Plan No. 4 of 1978 (43 FR 47713, October 17, 1978) transferred the authority of the Secretary of the Treasury to issue exemptions of the type proposed to the Secretary of Labor.

Statutory Findings

In accordance with section 408(a) of the Act and/or section 4975(c)(2) of the Code and the procedures set forth in 29 CFR Part 2570, Subpart B (55 FR 32836, 32847, August 10, 1990) and based upon the entire record, the Department makes the following findings:

(a) The exemptions are administratively feasible;

(b) They are in the interests of the plans and their participants and beneficiaries; and

(c) They are protective of the rights of the participants and beneficiaries of the plans.

General Electric Pension Trust (the Trust), Located in Fairfield, Connecticut

[Prohibited Transaction Exemption 96–34; Application No. D–09880]

Exemption

The restrictions of sections 406(a), 406(b)(1) and 406(b)(2) of the Act and the sanctions resulting from the application of section 4975 of the Code, by reason of section 4975(c)(1)(A) through (E) of the Code, shall not apply effective August 3, 1994, to the past and continued lease (the Lease) by the Trust of office space in a commercial office building located at 201 Mission Street in San Francisco, California (the Property), to GE Capital Aviation Services, Inc. (GE Aviation), a party in interest with respect to employee benefit plans participating in the Trust, provided the following conditions are met:

(a) All terms and conditions of the Lease are at least as favorable to the Trust as those which the Trust could have obtained in an arm's-length transaction with an unrelated party at the time the Lease was executed;

(b) The rent paid by GE Aviation to the Trust under the Lease is not less than the fair market rental value of the office space, as established by an independent qualified real estate appraiser;

(c) David P. Rhoades (Mr. Rhoades), acting as a qualified, independent fiduciary for the Trust (the Independent Fiduciary), reviewed all terms and conditions of the Lease prior to the transaction, as well as any subsequent modifications to the Lease, and determined that such terms and conditions would be in the best interests of the Trust at the time of the transaction; and

(d) The Independent Fiduciary represents the interests of the Trust for all purposes under the Lease as a qualified, independent fiduciary for the Trust, monitors the performance of the parties under the terms and conditions of the Lease and the exemption, and takes whatever action is necessary to safeguard the interests of the Trust throughout the duration of the Lease.

EFFECTIVE DATE: The exemption is effective for the period from August 3, 1994, until the scheduled termination date of the Lease, as it may be renewed or extended by the parties subject to the review and approval of the Independent Fiduciary, or, if earlier, the date the Lease is actually terminated by the parties.

For a more complete statement of the facts and representations supporting the Department's decision to grant this exemption refer to the notice of proposed exemption published on June 15, 1995, at 60 FR 31512.

NOTICE TO INTERESTED PERSONS: The applicant represents that it was unable to notify interested persons within the time period specified in the Federal Register notice published on June 15, 1995. However, pursuant to an agreement between the applicant and the Department, the Trust notified all interested persons (including active employees, former employees and retirees of General Electric Company (GE) and its affiliates) no later than March 11, 1996.[1] Interested persons were advised that they had until April 10, 1996 to comment and/or request a hearing on the proposed exemption.

WRITTEN COMMENTS AND MODIFICATIONS: By letter dated November 27, 1995, the applicant submitted the following comments and requests for modifications regarding the notice of proposed exemption (the Proposal).

The Effective Date paragraph in the Proposal states that the exemption, if granted, will be effective until the scheduled termination date of the Lease (i.e. September 16, 1999) or, if earlier, the date the Lease is actually terminated by the parties.

The applicant states that Paragraph 10 of the Summary of Facts and Representations in the Proposal (the Summary) contemplates that Mr. Rhoades, as the independent fiduciary acting for the Trust (i.e. the Independent Fiduciary), will oversee, review and approve any renewals or extensions of the Lease, if such renewals or extensions are in the best interests of the Trust. The applicant states further that Condition (c) of the Proposal indicates that the Independent Fiduciary will be responsible for reviewing any subsequent modifications to the Lease and determining that such

[1] The applicant represents that notice of the proposed exemption was provided to the active employees of GE and its affiliates who are participants and beneficiaries of the plans participating in the Trust by posting a notice (along with a copy of the proposed exemption as published in the Federal Register) at GE locations, in areas that are customarily used for notices to employees with regard to employee benefits or labor relations matters, on or before March 11, 1996. Former employees and retirees, along with other employees, were notified by means of publication of a notice in the 1994 Summary Annual Reports which were distributed to such persons during September and October 1995 via first class mail.

modifications would be in the best interests of the Trust.

The applicant represents that it is likely that the parties will negotiate whether to renew or extend the Lease at its termination, and such a renewal or extension may be in the best interests of the Trust depending on the then-current real estate market. Therefore, the Trust requests that the exemption be effective until the termination of the Lease, as it may be renewed or extended by the parties subject to the review and approval of the Independent Fiduciary.

The applicant represents further that if Mr. Rhoades, the current Independent Fiduciary, is no longer able to serve in that capacity, the Trust would retain a replacement Independent Fiduciary with the same qualifications as Mr. Rhoades and his firm. The replacement Independent Fiduciary would be required to make the same representations made by Mr. Rhoades regarding experience, independence from the GE and its affiliates, and understanding the duties, liabilities and responsibilities such person would have as a fiduciary under the Act. In addition, the replacement Independent Fiduciary would be required to enter into the same form of Independent Fiduciary Agreement used by Mr. Rhoades.

In response to the applicant's comments, the Department has modified the Effective Date paragraph in the Proposal by inserting, after the reference to the scheduled termination date of the Lease, the phrase ''... as it may be renewed or extended by the parties subject to the review and approval of the Independent Fiduciary''. The Department has also modified Conditions (c) and (d) of the Proposal by inserting ''Independent Fiduciary'' as a capitalized term in reference to Mr. Rhoades, which is meant to incorporate the applicant's concerns regarding the possibility of a replacement for Mr. Rhoades in the future.

The Department received two comment letters and various telephone calls from employees of GE who did not fully understand the Proposal's effect on benefits provided to participants and beneficiaries of the GE Pension Plan and other plans in the GE Trust (the GE Plans). In this regard, the applicant states that a special telephone line was established by GE to respond to such inquiries by participants and beneficiaries of the GE Plans. The applicant represents that GE received over 150 telephone calls in response to the Proposal and that additional information was provided to interested persons when requested.

The Department also received two comment letters from interested persons who oppose the granting of an exemption. One of the commenters objects to the transaction because the commenter believes that the Lease involves ''....the risking of GE Pension funds to be used in lieu of operating capital from the various GE businesses'' and exposes the GE Trust to ''high risks''. The other commenter does not approve of the Proposal but did not express any reasons for objecting to the transaction and could not be reached for further comments.

The applicant has responded to these comments by letter dated April 24, 1996. The applicant represents that the subject transaction does not involve the use of assets of the GE Pension Plan in lieu of operating capital of GE. Rather, the applicant states that the transaction involves the lease of space in an office building currently owned by the Trust to a GE subsidiary (i.e. GE Aviation) at terms equivalent to an arm's-length transaction, as reviewed and approved by a qualified independent fiduciary. The applicant notes that if the GE subsidiary had not entered into the Lease, the office space likely would have remained vacant for a longer period, resulting in loss of income to the Trust (including the GE Pension Plan). Therefore, the applicant maintains that the transaction is in the best interests of the Trust and does not in any way expose the Trust to higher risks than it would have been exposed to absent this transaction. The applicant concludes that there are sufficient safeguards in place to protect the interests of the Trust and its participants and beneficiaries.

No other comments, and no requests for a hearing, were received by the Department from interested persons.

Therefore, the Department has determined to grant the proposed exemption as modified herein.

FOR FURTHER INFORMATION CONTACT: Mr. E.F. Williams of the Department, telephone (202) 219–8194. (This is not a toll-free number.)

NBD Bancorp, Located in Detroit, Michigan

[Prohibited Transaction Exemption 96–35 Exemption Application No. D–09986]

Exemption

The restrictions of sections 406(b)(2) of the Act shall not apply to the merger of the INB Principal Stability Fund (the PS Fund) into the NBD Stable Asset Income Fund (the SAI Fund);[2] provided the following requirements are satisfied:

(1) On the date the merger is executed, the assets in the PS Fund and the assets in the SAI Fund will be valued in the same manner, under identical guidelines, by the same individuals;

(2) Upon completion of the merger of the PS Fund into the SAI Fund, the aggregate fair market value of the interests of the employee benefit plans (the Plans) participating in the SAI Fund immediately following the merger, together with any cash received in lieu of fractional units, equals the aggregate fair market value of each participating Plans' interest in such Funds immediately before the merger;

(3) The assets of each of the participating Plans are invested in the same type of investments both before and after the proposed merger;

(4) Neither NBD Bancorp nor any of its affiliates receives fees or commissions in connection with the merger;

(5) The Plans will pay no sales commissions or fees, as a result of the transaction; and

(6) A fiduciary who is acting on behalf of each affected Plan and who is independent of and unrelated to NBD Bancorp and any of its affiliates receives advance written notice of the merger of the PS Fund into the SAI Fund.

For a more complete statement of the facts and representations supporting the Department's decision to grant this exemption refer to the Notice of Proposed Exemption published on March 5, 1996, at 61 FR 8670.

FOR FURTHER INFORMATION CONTACT: Angelena C. Le Blanc of the Department, telephone (202) 219–8883 (This is not a toll-free number.)

Spreckels Industries, Inc. Employee Stock Ownership Plan (the ESOP); Spreckels Industries, Inc. Incentive Savings Plan for Union Hourly Employees (the Hourly Plan); and

Spreckels Industries, Inc. Employees' Incentive Savings Plan (the Incentive Plan; Collectively, the Plans), Located in Pleasanton, California

[Prohibited Transaction Exemption 96–36, Exemption Application Nos. D–09999 through D–10001]

Exemption

The restrictions of sections 406(a)(1)(A), 406(a)(1)(E), 406(a)(2), 407(a), 406(b)(1), and 406(b)(2) of the Act and the sanctions resulting from the

[2] For purposes of this exemption, the PS Fund and the SAI Fund described herein are collectively referred to as the Funds.

application of section 4975 of the Code, by reason of section 4975(c)(1) (A) and (E) of the Code, shall not apply to the acquisition, holding or exercise by the Plans of certain warrants (the Warrants) for the purchase of Class A new common stock (the New Common Stock) of Spreckels Industries, Inc. (the Employer), a party in interest with respect to the Plans; provided that the following conditions are satisfied:

(a) An independent fiduciary (the I/F) will manage the Warrants and monitor the value of the Warrants at all times and will be empowered to assign, transfer, sell, and exercise the Warrants in order to serve the best interest of the Plans and their participants and beneficiaries;

(b) The fair market value of the Warrants will at no time exceed twenty-five percent (25%) of the value of the total assets of the Hourly Plan or the Incentive Plan;

(c) The Warrants that the Plans will acquire resulted from a bankruptcy proceeding, in which all holders of the Class A old common stock in Spreckels Industries, Inc. were treated in a like manner, including the Plans;

(d) The Plans will not incur any expenses or fees in connection with the proposed transactions;

(e) Any assignment, sale, or other transfer of the Warrants will not involve a party in interest with respect to the Plans, as defined in section 3(14) of the Act, unless such transfer is to the Employer, pursuant to an exercise of the Warrants; and

(f) The I/F will determine the fair market value of the Warrants upon acquisition by the Plans, and an independent qualified appraiser will determine the fair market value of the Warrants on a periodic basis (but not less frequently than annually).

Written Comments

In the Notice of Proposed Exemption (the Notice), the Department of Labor (the Department) invited all interested persons to submit written comments and requests for a hearing on the proposed exemption within forty-five (45) days of the date of the publication of the Notice in the Federal Register on January 31, 1996. All comments and requests for hearing were due by March 18, 1996.

During the comment period, the Department received no requests for hearing. However, the Department did receive a comment letter from the applicant, dated April 8, 1996, which informed the Department of changes in the facts as represented in the proposed exemption. In this regard, the Employer has engaged Consulting Fiduciaries, Inc. (CFI) to replace L. Scott Maclise (Mr. Maclise), a registered investment advisor with Linsco/Private Ledger Financial Services, who was appointed to serve as the I/F on behalf of the Plans for the purposes of the exemption. In the comment letter, the Employer requested concurrence from the Department that the exemption would be granted notwithstanding the replacement of Mr. Maclise as the I/F for the Plans.

Attached to the comment letter, the applicant included: (1) A copy of a letter, dated April 2, 1996, which details the agreement between the Employer and CFI concerning the engagement of CFI to provide certain services as independent fiduciary on behalf of the Plans; and (2) a letter, dated April 2, 1996, from CFI to the Department in which CFI made certain representations. In this regard, CFI has accepted appointment as I/F on behalf of the Plans for the purposes of the transactions which are the subject of this exemption and, except in the event of discharge or resignation as described in the agreement with the Employer, will serve throughout the duration of the transactions.

CFI represents that it is qualified to serve as I/F, in that it is a registered investment adviser under the Investment Advisers Act of 1940 and provides professional, independent fiduciary decision making, consultation, and alternative dispute resolution services to plans, plan sponsors, trustees, and investment advisers. Further, CFI is experienced in representing clients as a fiduciary in stock transactions.

CFI represents that it has the power to negotiate and act independently of the Employer and its officers, directors, shareholders, agents and representatives with respect to the transactions which are the subject of this exemption. In this regard, CFI is not affiliated with the Employer and the income CFI receives from the Employer is expected to represent less than one percent (1%) on an annualized basis of its income over the life of its engagement as I/F.

CFI represents that it understands its duties as I/F under the Act and the Code and will assume all duties, responsibilities, and obligations imposed on it as I/F of the Plans in connection with the transactions which are the subject of this exemption. In this regard, CFI represents that it will take whatever acts are necessary to review, analyze, negotiate, monitor, and approve or disapprove the transactions and will be responsible for the Plans' acquisition and holding of the Warrants. Bearing in mind its fiduciary duties under the Act, CFI represents that it will determine whether the transactions: (a) Are prudent and for the exclusive purpose of providing benefits to participants; (b) are fair to the Plans from a financial point of view; and (c) are in accordance with the terms and conditions as set forth in the Notice.

CFI will decide on behalf of the Plans (a) whether or not the Plans should acquire and hold the Warrants; and (b) when, if at all, the Warrants should be exercised to acquire New Common Stock or sold and the proceeds used to acquire such stock. With respect to the acquisition of the Warrants, CFI represents that it will conduct due diligence to evaluate whether the Plans should enter into the transactions which are the subject of this exemption. CFI represents that it bears full power to manage and monitor the value of the Warrants at all times. In this regard, CFI represents that it will determine the fair market value of the Warrants upon acquisition by the Plans.

With respect to the holding of the Warrants by the Plans, CFI represents that such holding will not impair the diversification, prudence, or liquidity of the Plans. In this regard, CFI represents that it will be responsible, as appropriate, for insuring that the Warrants will be appraised on a periodic basis (but not less frequently than annually).

CFI represents that it is empowered to assign, transfer, sell, and exercise the Warrants in order to serve the best interests of participants and beneficiaries of the Plan. In this regard, CFI represents that it will not in any way transfer, assign, or sell the Warrants to a ''party in interest'' within the meaning of section 3(14) of the Act or section 4975(e)(2) of the Code, unless such a transfer is to the Employer pursuant to an exercise of such Warrants.

After giving full consideration to the entire record, including the written comment from the applicant, the Department has decided to grant the exemption, as described and concurred in above. In this regard, the comment letter submitted by the applicant to the Department has been included as part of the public record of the exemption application. The complete application file, including all supplemental submissions received by the Department, is made available for public inspection in the Public Documents Room of the Pension Welfare Benefits Administration, Room N–5638, U.S. Department of Labor, 200 Constitution Avenue, N.W., Washington, D.C. 20210.

For a more complete statement of the facts and representations supporting the

Department's decision to grant this exemption refer to the Notice published on January 31, 1996 at 61 FR 3470.

FOR FURTHER INFORMATION CONTACT: Angelena C. Le Blanc of the Department, telephone (202) 219–8883 (This is not a toll-free number.)

Budge Clinic Profit Sharing Plan and Trust (the Plan), Located in Logan, Utah

[Prohibited Transaction Exemption 96–37; Exemption Application No. D–10142]

Exemption

The restrictions of sections 406(a), 406(b)(1) and (b)(2) of the Act and the sanctions resulting from the application of section 4975 of the Code, by reason of section 4975(c)(1)(A) through (E) of the Code, shall not apply to the sale of certain improved real property located in Logan, Utah (the Property) by the Plan to IHC Health Services, Inc., a party in interest with respect to the Plan; provided that the following conditions are satisfied:

(A) All terms and conditions of the transaction are no less favorable to the Plan than those which the Plan could obtain in an arm's-length transaction with an unrelated party;

(B) The Plan receives a cash purchase price for the Property which is no less than the fair market value of the Property as of the sale date; and

(C) The Plan does not incur any expenses or suffer any loss with respect to the transaction.

For a more complete statement of the facts and representations supporting this exemption, refer to the notice of proposed exemption published on March 12, 1996 at 61 FR 10015.

FOR FURTHER INFORMATION CONTACT: Ronald Willett of the Department, telephone (202) 219–8881. (This is not a toll-free number.)

General Information

The attention of interested persons is directed to the following:

(1) The fact that a transaction is the subject of an exemption under section 408(a) of the Act and/or section 4975(c)(2) of the Code does not relieve a fiduciary or other party in interest or disqualified person from certain other provisions to which the exemptions does not apply and the general fiduciary responsibility provisions of section 404 of the Act, which among other things require a fiduciary to discharge his duties respecting the plan solely in the interest of the participants and beneficiaries of the plan and in a prudent fashion in accordance with section 404(a)(1)(B) of the Act; nor does it affect the requirement of section 401(a) of the Code that the plan must operate for the exclusive benefit of the employees of the employer maintaining the plan and their beneficiaries;

(2) These exemptions are supplemental to and not in derogation of, any other provisions of the Act and/or the Code, including statutory or administrative exemptions and transactional rules. Furthermore, the fact that a transaction is subject to an administrative or statutory exemption is not dispositive of whether the transaction is in fact a prohibited transaction; and

(3) The availability of these exemptions is subject to the express condition that the material facts and representations contained in each application accurately describes all material terms of the transaction which is the subject of the exemption.

Signed at Washington, D.C., this 6th day of May, 1996.

Ivan Strasfeld,

Director of Exemption Determinations, Pension and Welfare Benefits Administration, Department of Labor.

[FR Doc. 96–11744 Filed 5–9–96; 8:45 am]

BILLING CODE 4510–29–P

Office of the Assistant Secretary for Veterans' Employment and Training

Secretary of Labor's Advisory Committee for Veterans' Employment and Training; Notice of Meeting

The Secretary's Advisory Committee for Veterans' Employment and Training was established under Section 4110 of title 38, United States Code, to bring to the attention of the Secretary, problems and issues relating to veterans' employment and training.

Notice is hereby given that the Secretary of Labor's Advisory Committee for Veterans' Employment and Training will meet on Thursday June 6, 1996 at the Disabled American Veterans National Service and Legislative Headquarters 807 Maine Avenue, S.W., Washington, D.C. 20024 at 9:00 a.m. to 4:00 p.m. and Friday June 7, 1996 in the Department of Labor Secretary's Conference Room, S–2508, 200 Constitution Avenue, N.W., Washington, D.C. at 8:30 a.m. to noon.

Written comments are welcome and may be submitted by addressing them to: Mr. Thomas S. Keefe, Special Assistant, Office of the Assistant Secretary for Veterans' Employment and Training, U.S. Department of Labor, 200 Constitution Avenue, N.W., Room S1315, Washington, D.C. 20210.

The primary items on the agenda are:

- Adoption of minutes of the previous meeting.
- Budget briefing—FY 1996 & 1997.
- Pending legislation (S 1711).
- National Skills Board briefing.
- Veterans Preference Issues.
- Office of the DOL Inspector General briefing on OFCCP.
- WREI video.
- Planning session of a fall Veterans Employment Forum.

The meeting is open to the public.

Persons with disabilities, needing special accommodations, should contact Thomas S. Keefe at telephone number 202–219–9116 no later than Friday, May 31.

Signed at Washington, D.C. this 3rd day of May, 1996.

Preston M. Taylor Jr.,

Assistant Secretary for Veterans' Employment and Training.

[FR Doc. 96–11766 Filed 5–9–96; 8:45 am]

BILLING CODE 4510–79–M

LEGAL SERVICES CORPORATION

Sunshine Act Meeting

TIME AND DATE: The Provision for the Delivery of Legal Services Committee of the Legal Services Corporation's Board of Directors will meet on May 19, 1996. The meeting will begin at 2:00 p.m. and continue until conclusion of the committee's agenda.

LOCATION: Legal Services Corporation, 750 First Street NE, 11th Floor, Washington, DC 20002, (202) 336–8800.

STATUS OF MEETING: Open.

MATTERS TO BE CONSIDERED:

1. Approval of Agenda.
2. Consider and act on recommendtion for Board action on a suggested list of priorities that grantee boards may use in setting local priorities.
3. Report by the OIG on its plans for implementation of Section 509 of Pub. L. 104–134 (H.R. 3019).
4. Report by the Directors of OPEAR and OPS on the Corporation's implementation of competitive grantmaking in '96 and plans for '97, and other initiatives.
5. Provide direction to staff with respect to publication of a draft revised Accounting Guide for Recipients and Auditors in the Federal Register for public comment.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, General Counsel, (202) 336–8800.

SPECIAL NEEDS: Upon request, meeting notices will be made available in alternate formats to accommodate visual and hearing impairments. Individuals who have a disability and need an

accommodation to attend the meeting may notify Barbara Asante, at (202) 336–8800.

Dated: May 7, 1996.

Victor M. Fortuno,

General Counsel.

[FR Doc. 96–11809 Filed 5–8–96; 12:28 pm]

BILLING CODE 7050–01–P

Sunshine Act Meeting

TIME AND DATE: The Finance Committee of the Legal Services Corporation's Board of Directors will meet on May 19, 1996. The meeting will begin at 2:00 p.m. and continue until conclusion of the committee's agenda.

LOCATION: Legal Services Corporation, 750 First Street NE, 11th Floor, Washington, DC 20002, (202) 336–8800.

STATUS OF MEETING: Open.

MATTERS TO BE CONSIDERED:

1. Approval of Agenda.
2. Receive report of Thompson, Cobb, Bazilio & Associates, Certified Public Accountants, on their audit of the Corporation's FY '95 financial statements.
3. Consider and adopt a proposed revised Consolidated Operating Budget for FY '96, implementing Pub. L. 104–134 (H.R. 3019), to recommend to the Board for its adoption.
4. Consider and act on other business.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, General Counsel, (202) 336–8800.

SPECIAL NEEDS: Upon request, meeting notices will be made available in alternate formats to accommodate visual and hearing impairments. Individuals who have a disability and need an accommodation to attend the meeting may notify Barbara Asante, at (202) 336–8800.

Dated: May 7, 1996.

Victor M. Fortuno,

General Counsel.

[FR Doc. 96–11810 Filed 5–8–96; 12:28 pm]

BILLING CODE 7050–01–P

Sunshine Act Meeting

TIME AND DATE: The Operations and Regulations Committee of the Legal Services Corporation's Board of Directors will meet on May 19, 1996. The meeting will begin at 2:00 p.m. and continue until conclusion of the committee's agenda.

LOCATION: Legal Services Corporation, 750 First Street NE, 11th Floor, Washington, DC 20002, (202) 336–8800.

STATUS OF MEETING: Open.

MATTERS TO BE CONSIDERED:

1. Approval of Agenda.
2. Consider and act on staff and OPM recommendations relating to internal personnel policies of the Corporation.
3. Consider and act on measures or steps necessary for the implementation of new restrictions and requirements imposed by Pub. L. 104–134 (H.R. 3019) and the provision of guidance to the public as to those restrictions and requirements.
4. Consider and act on other business.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, General Counsel, (202) 336–8800.

SPECIAL NEEDS: Upon request, meeting notices will be made available in alternate formats to accommodate visual and hearing impairments. Individuals who have a disability and need an accommodation to attend the meeting may notify Barbara Asante, at (202) 336–8800.

Dated: May 7, 1996.

Victor M. Fortuno.

General Counsel.

[FR Doc. 96–11811 Filed 5–8–96; 12:28 pm]

BILLING CODE 7050–01–P

Sunshine Act Meeting

TIME AND DATE: The Legal Services Corporation Board of Directors will meet on May 20, 1996. The meeting will begin at 9:00 a.m. and continue until conclusion of the Board's agenda.

LOCATION: Legal Services Corporation, 750 First Street NE, 11th Floor, Washington, DC 20002, (202) 336–8800.

STATUS OF MEETING: Open, except that a portion of the meeting may be closed pursuant to a unanimous vote of the Board of Directors to hold an executive session. At the closed session, the Board may be briefed by management on internal operational and personnel matters and by the Corporation's Inspector General on activities of the Office of Inspector General. In addition, the General Counsel will report to the Board on litigation to which the Corporation is or may become a party and the Board may act on the matters reported. The closing will be authorized by the relevant sections of the Government in the Sunshine Act [5 U.S.C. section 552b(c) (10)] and the corresponding regulation of the Legal Services Corporation [45 C.F.R. section 1622.5(h)].[1] A copy of the General Counsel's Certification, that the closing is authorized by law, will be posted for public inspection at the Corporation's headquarters, located at 750 First Street NE, Washington, DC 20002, in its 11th floor reception area, and will also be available upon request.

MATTERS TO BE CONSIDERED:

Open Session

1. Approval of Agenda.
2. Approval of Minutes of February 24, 1996, meeting.
3. Approval of February 24, 1996, executive session minutes.
4. Approval of Minutes of March 20, 1996, meeting.
5. Receive report of Thompson, Cobb, Bazilio & Associates, Certified Public Accountants, on their audit of the Corporation's FY '95 financial statements.
6. Chairman's and Members' Reports.
7. President's Report.
8. Inspector General's Report.
9. Consider and act on Board's Operations and Regulations Committee Report.
   a. Internal personnel policies of the Corporation.
   b. Implementation of Pub. L. 104–134 (H.R. 3019) and provision of guidance thereon.
10. Consider and act on the report of the Board's Finance Committee, including the adoption of a Consolidated Operating Budget.
11. Consider and act on the report of the Board's Committee on the Provision for the Delivery of Legal Services, including the adoption of a suggested list of priorities that grantees' boards may use in setting local priorities.
12. Consider and act on proposed Report of the Board of Directors to accompany the Inspector General's Semi-annual Report to the Congress for the period of October 1, 1995–March 31, 1996.

Closed Session

13. Inspector General's briefing of the Board on activities of LSC's Office of Inspector General.
14. Management's briefing of the Board on internal operations and personnel matters.
15. Consider and act on the General Counsel's report on potential and pending litigation involving the Corporation and on a request for indemnification filed in connection with a pending lawsuit.

Open Session

16. Public comment.
17. Consider and act on other business.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, General Counsel, (202) 336–8800.

SPECIAL NEEDS: Upon request, meeting notices will be made available in alternate formats to accommodate visual and hearing impairments. Individuals who have a disability and need an accommodation to attend the meeting should contact Barbara Asante, at (202) 336–8800.

[1] Briefings do not constitute ''meetings,'' as defined by the Government in the Sunshine Act. Notice of briefings is here provided as a courtesy to the public.

Dated: May 7, 1996.

Victor M. Fortuno,

General Counsel.

[FR Doc. 96–11812 Filed 5–8–96; 12:28 pm]

BILLING CODE 7050–01–P

NATIONAL FOUNDATION ON THE ARTS AND HUMANITIES

Cooperative Agreement for a Theater Residency Program for Playwrights

AGENCY: National Endowment for the Arts.

ACTION: Notice of availability.

SUMMARY: The National Endowment for the Arts requests proposals leading to the award of a Cooperative Agreement for the development, implementation, administration, and evaluation of a playwrights' theater residency program. Under the Cooperative Agreement, a minimum of 10 playwrights will be awarded $25,000 each for residencies at theater institutions. The residency stipends will recognize significant accomplishment or promise and will allow playwrights to fulfill self-defined artistic and community-based goals. those interested in receiving the Solicitation should reference Program Solicitation PS 96–05 in their written request and include two (2) self-addressed labels. Verbal requests for the Solicitation will not be honored.

DATES: Program Solicitation PS 96–05 is scheduled for release approximately May 24, 1996 with proposals due on June 24, 1996.

ADDRESSES: Requests for the Solicitation should be addressed to National Endowment for the Arts, Grants & Contracts Office, Room 618, 1100 Pennsylvania Ave., NW., Washington, DC 20506.

FOR FURTHER INFORMATION CONTACT: William I. Hummel, Grants and Contracts Office, National Endowment for the Arts, 1100 Pennsylvania Ave., NW, Washington, DC 20506 (202/682–5482).

William I. Hummel,

Coordinator, Cooperative Agreements and Contracts.

[FR Doc. 96–11650 Filed 5–9–96; 8:45 am]

BILLING CODE 7537–01–M

National Endowment for the Arts; International Advisory Meeting

Pursuant to Section 10(a)(2) of the Federal Advisory Committee Act (Public Law 92–463), as amended, notice is hereby given that a meeting of the International Advisory Panel (Federal Advisory Committee on International Exhibitions Section) to the National Council on the Arts will meet on May 31, 1996 from 10:00 a.m. to 3:30 p.m. in Room 716, at the Nancy Hanks Center, 1100 Pennsylvania Avenue, NW., Washington, DC 20506.

This meeting is for the purpose of application evaluation, under the National Foundation on the Arts and the Humanities Act of 1965, as amended, including discussion of information given in confidence to the Agency by grant applicants. In accordance with the determination of the Chairman of June 22, 1995, these sessions will be closed to the public pursuant to subsections (c)(4), (6) and 9(B) of section 552b of Title 5, United States Code.

Further information with reference to this meeting can be obtained from Ms. Kathy Plowitz-Worden, Panel Coordinator, National Endowment for the Arts, Washington, DC 20506, or call (202) 682–5691.

Dated: May 6, 1996.

Kathy Plowitz-Worden,

Panel Coordinator, Office of Guidelines and Panel Operations, National Endowment for the Arts.

[FR Doc. 96–11723 Filed 5–9–96; 8:45 am]

BILLING CODE 7537–01–M

NATIONAL COMMUNICATIONS SYSTEM

National Security Telecommunications Advisory Committee

AGENCY: National Communications System (NCS).

ACTION: Notice of meeting.

SUMMARY: The President's National Security Telecommunications Advisory Committee will hold a meeting to exchange facts and information on the threats to the nation's information infrastructure to include a brief from the National Security Agency. This special meeting will be held Thursday, May 23, 1996, from 9:00 a.m. to 12:00 p.m. at 4301 North Fairfax Drive, Room 272, Arlington, VA 22203. The agenda is as follows:

—Call to Order/Welcoming Remarks
—Threat Briefing
—Discussion
—Closing Remarks/Adjournment

Due to the classification of the information to be discussed, this meeting will be closed to the public in the interest of national security.

FOR FURTHER INFORMATION CONTACT: Telephone (703) 607–6221 or write the Manager, National Communications System, 701 South Court House Rd., Arlington, VA 22204–2198.

Dennis Bodson,

Chief, Technology and Standards.

[FR Doc. 96–11795 Filed 5–9–96; 8:45 am]

BILLING CODE 5000–03–M

NATIONAL SCIENCE FOUNDATION

Special Emphasis Panel in Biological Sciences; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation (NSF) announces the following meeting.

Name: Special Emphasis Panel in biological Sciences (#1754).

Date and Time: May 30–31, 1996; 9:00 a.m.–5:30 p.m.

Type of Meeting: Closed.

Contact Person: Carol Colby, Program Officer for Behavioral Neuroscience in the Division of Integrative Biology and Neuroscience, Room 685, National Science Foundation 4201 Wilson Boulevard, Arlington, VA 22230, Telephone: (703) 306–1416.

Purpose of Meeting: To provide advice and recommendations concerning proposals submitted to NSF for financial support.

Agenda: To review and evaluate Collaborative Research in Neuroscience, Computer and Mathematical Sciences and Engineering (CRI) proposals as part of the selection process for awards.

Reason for Closing: The proposals being reviewed include information of a proprietary or confidential nature, including technical information; financial data, such as salaries; and personal information concerning individuals associated with the proposals. These matters are exempt under 5 U.S.C. 5522b(c), (4) and (6) of the Government in the Sunshine Act.

Dated: May 6, 1996.

M. Rebecca Winkler,

Committee Management Officer.

[FR. Doc. 96–11666 Filed 5–9–96; 8:45 am]

BILLING CODE 7555–01–M

Special Emphasis Panel in Electrical and Communication Systems; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name and Committee Code: Special Emphasis Panel in Electrical and Communications Systems (1196).

Date and Time: May 28, 1996; 8:00 a.m. to 6:00 p.m.

Place: Room 365, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230.

Type of Meeting: Closed.

Contact Person: Dr. Paul Werbos, Program Director, Neuroengineering, Division of Electrical and Communications System, Room 675, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230.

Telephone: (703) 306–1340.

Purpose of Meeting: To provide advice and recommendations concerning proposals submitted to NSF for financial support.

Agenda: To review and evaluate ARI proposals that were submitted to the Division of Electrical and Communication Systems as part of the selection process for awards.

Reason for Closing: The proposals being reviewed include information of a proprietary or confidential nature, including technical information; financial data, such as salaries and personal information concerning individuals associated with the proposals. These matters are exempt under 5 U.S.C. 552b(c)(4) and (6) of the Government in the Sunshine Act.

Dated: May 6, 1996.

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 96–11667 Filed 5–9–96; 8:45 am]

BILLING CODE 7555–01–M

National Science Foundation

Special Emphasis Panel in Science Resources Studies; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Special Emphasis Panel in Science Resources Studies (#1211).

Date and Time: May 30, 1996–9:00 a.m. to 4:00 p.m.; May 31, 1996–9:00 a.m. to 12:00 p.m.

Place: Room 340, 4201 Wilson Blvd., Arlington, Virginia.

Type of Meeting: Partially Open.

Contact Person: Ann Lanier, Project Director, Survey of Academic Research Facilities, Division of Science Resources Studies, National Science Foundation, Room 965, 4201 Wilson Boulevard, Arlington, VA 22230, Telephone: (703) 306–1774, ext. 6910.

Purpose of Meeting: To review and comment on the content, structure, and layout of the biennial report to Congress, Scientific and Engineering Research Facilities at Universities and Colleges: 1996

Agenda: May 30—Review and comment on the DRAFT data tables for the report and review and comment on the body of the report. May 31—Review and comment on the DRAFT of the body of the report.

Reason for Closing: The closed portion of the meeting on May 30th will disclose data from individual institutions that is privileged or confidential. These matters are within exemption (4) of 5 U.S.C. 552b(c) of the Government in the Sunshine Act.

Dated: May 6, 1996.

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 96–11668 Filed 5–9–96; 8:45 am]

BILLING CODE 7555–01–M

OFFICE OF PERSONNEL MANAGEMENT

[RI 30–9]

Proposed Collection; Comment Request for Reclearance of Information Collection

AGENCY: Office of Personnel Management.

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (Public Law 104–13, May 22, 1995), this notice announces that the Office of Personnel Management intends to submit to the Office of Management and Budget a request for reclearance of the following information collection. RI 30–9, Reinstatement of Disability Annuity Previously Terminated Because of Restoration to Earning Capacity, informs disability annuitants of their right to request restoration under title 5, U.S.C., Section 8337. It also specifies the conditions to be met and the documentation required for a person to request reinstatement.

Approximately 200 forms are completed annually. The form takes approximately 60 minutes to respond, including a medical examination. The annual estimated burden is 200 hours. Burden may vary depending on the time required for a medical examination.

For copies of this proposal, contact Jim Farron on (202) 418–3208, or E-mail to jmfarron@mail.opm.gov

DATES: Comments on this proposal should be received on or before July 9, 1996.

ADDRESSES: Send or deliver comments to—Lorraine E. Dettman, Chief, Operations Support Division, Retirement and Insurance Service, U.S. Office of Personnel Management, 1900 E Street, NW, Room 3349, Washington, DC 20415.

FOR INFORMATION REGARDING ADMINISTRATIVE COORDINATION CONTACT: Mary Beth Smith-Toomey, Management Services Division, (202) 606–0623.

U.S. Office of Personnel Management.

Lorraine A. Green,

Deputy Director.

[FR Doc. 96–11750 Filed 5–9–96; 8:45 am]

BILLING CODE 6325–01–M

Federal Prevailing Rate Advisory Committee; Open Committee Meeting

According to the provisions of section 10 of the Federal Advisory Committee Act (Pub. L. 92–463), notice is hereby given that meetings of the Federal Prevailing Rate Advisory Committee will be held on—

Thursday, June 13, 1996
Thursday, June 27, 1996
Thursday, July 25, 1996
Thursday, August 8, 1996
Thursday, August 22, 1996
Thursday, September 12, 1996

The meetings will start at 10:45 a.m. and will be held in Room 5A06A, Office of Personnel Management Building, 1900 E Street, NW., Washington, DC.

The Federal Prevailing Rate Advisory Committee is composed of a Chair, five representatives from labor unions holding exclusive bargaining rights for Federal blue-collar employees, and five representatives from Federal agencies. Entitlement to membership on the Committee is provided for in 5 U.S.C. 5347.

The Committee's primary responsibility is to review the Prevailing Rate System and other matters pertinent to establishing prevailing rates under subchapter IV, chapter 53, 5 U.S.C., as amended, and from time to time advise the Office of Personnel Management.

These scheduled meetings will start in open session with both labor and management representatives attending. During the meeting either the labor members or the management members may caucus separately with the Chair to devise strategy and formulate positions. Premature disclosure of the matters discussed in these caucuses would unacceptably impair the ability of the Committee to reach a consensus on the matters being considered and would disrupt substantially the disposition of its business. Therefore, these caucuses will be closed to the public because of a determination made by the Director of the Office of Personnel Management under the provisions of section 10(d) of the Federal Advisory Committee Act (Pub. L. 92–463) and 5 U.S.C. 552b(c)(9)(B). These caucuses may, depending on the issues involved, constitute a substantial portion of the meeting.

Annually, the Chair compiles a report of pay issues discussed and concluded recommendations. These reports are available to the public, upon written request to the Committee's Secretary.

The public is invited to submit material in writing to the Chair on Federal Wage System pay matters felt to be deserving of the Committee's attention. Additional information on

these meetings may be obtained by contacting the Committee's Secretary, Office of Personnel Management, Federal Prevailing Rate Advisory Committee, Room 5559, 1900 E Street, NW., Washington, DC 20415 (202) 606–1500.

Dated: May 3, 1996.

Phyllis G. Foley,

Chair, Federal Prevailing Rate Advisory Committee.

[FR Doc. 96–11749 Filed 5–9–96; 8:45 am]

BILLING CODE 6325–01–M

SECURITIES AND EXCHANGE COMMISSION

[Release No. 35–26514]

Filings Under the Public Utility Holding Company Act of 1935, as Amended (''Act'')

May 3, 1996.

Notice is hereby given that the following filing(s) has/have been made with the Commission pursuant to provisions of the Act and rules promulgated thereunder. All interested persons are referred to the application(s) and/or declaration(s) for complete statements of the proposed transaction(s) summarized below. The application(s) and/or declaration(s) and any amendments thereto is/are available for public inspection through the Commission's Office of Public Reference.

Interested persons wishing to comment or request a hearing on the application(s) and/or declaration(s) should submit their views in writing by May 28, 1996, to the Secretary, Securities and Exchange Commission, Washington, D.C. 20549, and serve a copy on the relevant applicant(s) and/or declarant(s) at the address(es) specified below. Proof of service (by affidavit or, in case of an attorney at law, by certificate) should be filed with the request. Any request for hearing shall identify specifically the issues of fact or law that are disputed. A person who so requests will be notified of any hearing, if ordered, and will receive a copy of any notice or order issued in the matter. After said date, the application(s) and/or declaration(s), as filed or as amended, may be granted and/or permitted to become effective.

Louisiana Power & Light Company (70–8487)

Louisiana Power & Light Company (''LP&L'' or ''Company''), 639 Loyola Avenue, New Orleans, Louisiana 70113, an electric public-utility subsidiary company of Entergy Corporation, a registered holding company, has filed a post-effective amendment to its application-declaration under section 6(a), 7, 9(a) and 10 of the Act and rule 54 thereunder.

By order dated October 3, 1995 (HCAR No. 26387) (''Order''), the Commission authorized, among other things, LP&L to issue and sell, through December 31, 1997: (1) Directly or indirectly through a subsidiary, not more than $610 million principal amount of its first mortgage bonds (''Bonds''), debentures (''Debentures'') and preferred securities of a subsidiary of LP&L to be issued in one or more new series; and (2) collateral bonds in a total aggregate principal amount of $75 million to secure certain tax-exempt bonds.

LP&L now proposes to issue and sell the Debentures either unsecured or secured by certain LP&L assets, junior and subordinate to the first lien (''Junior Lien'') of its Mortgage and Deed of Trust dated April 1, 1944, to Bank of Montreal Trust Company (''Mortgage''). In addition, LP&L proposes that the Debentures may be secured by a pledge of first mortgage bonds issued under the Mortgage.

The Debentures will be issued under either LP&L's Debenture Indenture, Indenture for Debt Securities or its Subordinated Debenture Indenture, (each, a ''Debenture Indenture''), as may be supplemented from time to time. Debentures issued under the form of the Debenture Indenture initially will be secured obligations of the Company, entitled to the Junior Lien on the Company's assets. In connection with the issuance of Debentures secured by the Junior Lien under such Debenture Indenture, the Company may provide security for the holders of such Debentures in the form of first mortgage bonds issued under the Mortgage as it may be supplemented. Such first mortgage bonds would be issued on the basis of unfunded net property additions and/or previously-retired first mortgage bonds and delivered to the trustee under such Debenture Indenture. The first mortgage bonds could be issued in an amount equal to the principal amount of such Debentures and bear interest at a rate of interest equivalent to the rate of interest on such Debentures or bear no interest. These first mortgage bonds would be separate and apart from the Bonds (proposed to be issued and sold in an aggregate principal amount of not more than $610 million).

The Company's Amended and Restated Articles of Incorporation (''Charter'') provide, for the benefit of holders of preferred securities, restrictions on the amount of unsecured indebtedness issued by the Company. As a result of these restrictions, the Company proposes to issue Debentures secured by either the Junior Lien or a pledge of first mortgage bonds in order that any such Debentures so issued would not constitute unsecured debt for purposes of the Charter.

The Debenture Indenture under which the Company may issue Debentures secured by the Junior Lien and/or such first mortgage bonds provides for the amendment and restatement of such Debenture Indenture in its entirety, without the consent of the holders of the Debentures outstanding thereunder, to remove the Junior Lien and to release any such collateral first mortgage bonds such that the Debentures would become entirely unsecured obligations of the Company. Such an amendment eliminating the Junior Lien would be subject to the following conditions: (1) No event of default has occurred and is continuing under the Debenture Indenture; and (2)(a) the Company's Charter has been duly amended to eliminate the restrictions on the issuance of unsecured indebtedness, (b) all preferred securities issued by the Company and outstanding are paid, retired or redeemed, or (c) holders of such preferred securities consent to amend the Company's Charter for the purpose of eliminating such restrictions.

The Order also authorized LP&L to enter into arrangements to finance or refinance pollution control facilities (''Facilities'') through the issuance of tax-exempt revenue bonds up to an aggregate principal amount of $65 million, including the possible issuance of an irrevocable letter of credit from a bank (''Bank'') and/or pledge of one or more series of first mortgage bonds up to an aggregate principal amount of $75 million to be used as collateral for the tax-exempt revenue bonds. As an alternative to the security provided by the Bank, in order to obtain a more favorable rating on tax-exempt bonds and consequently improve the marketability thereof, the Company may (a) determine to provide an insurance policy for the payment of the principal of and/or interest and/or premium on one or more series of tax-exempt bonds, and/or (b) provide security for holders of tax-exempt bonds and/or the Bank equivalent to the security accorded to (i) holders of first mortgage bonds outstanding under the Company's Mortgage by obtaining the authentication of and pledging one or more new series of first mortgage bonds (''Collateral Bonds'') under the Mortgage as it may be supplemented or (ii)

holders of Debentures outstanding under the Debenture Indenture that are secured by the Junior Lien by obtaining the authentication of and pledging one or more series of Debentures (the ''Collateral Debentures'') under the Debenture Indenture.

The Collateral Bonds would be issued on the basis of unfunded net property additions and/or previously-retired first mortgage bonds; Collateral Debentures would be issued pursuant to the terms of a Debenture Indenture. The Collateral Bonds or Collateral Debentures would be delivered to the trustee under the Indenture and/or to the Bank to evidence and secure the Company's obligation to pay the purchase price of the Facilities and the Company's obligation to reimburse the Bank under any reimbursement agreement.

The Collateral Bonds or Collateral Debentures could be issued in several ways. First, if tax-exempt bonds bear a fixed interest rate, the Collateral Bonds or Collateral Debentures could be issued in an amount equal to the principal amount of such tax-exempt bonds and bear interest at a rate equal to the rate of interest on such tax-exempt bonds. Secondly, the Collateral Bonds or Collateral Debentures could be issued in an amount equivalent to the principal amount of such tax-exempt bonds plus an amount equal to interest on the Bonds for a specified period. In such case, the Collateral Bonds or Collateral Debentures would bear no interest. Thirdly, the Collateral Bonds or Collateral Debentures could be issued in an amount equivalent to the principal amount of such tax-exempt bonds or in such amount plus an amount equal to interest on those Bonds for a specified period, but carry a fixed interest rate that would be lower than the fixed interest rate of the tax-exempt bonds. Fourthly, the Collateral Bonds or Collateral Debentures could be issued in a principal amount equivalent to the principal amount of tax-exempt bonds at an adjustable rate of interest, varying with such tax-exempt bonds but having a ''cap'' (not greater than 15%) above which the interest on Collateral Bonds or Collateral Debentures could not rise.

Each series of the Collateral Bonds or Collateral Debentures that bear interest would bear interest at a fixed interest rate or initial adjustable interest rate not to exceed 15%. The maximum aggregate principal amount of Collateral Bonds and Collateral Debentures that would be issued is $75 million. The terms of the Collateral Bonds or Collateral Debentures relating to maturity, interest payment dates, if any, redemption provisions and acceleration will correspond to the terms of the related tax-exempt bonds. Upon issuance, the terms of each series of the Collateral Bonds or Collateral Debentures will not vary during the life of such series except for the interest rate of any such series that bears interest at an adjustable rate.

Northern States Power Company and Wisconsin Energy Corporation, et al. (70–8833)

Northern States Power Company (''NSP''), 414 Nicollet Mall, Minneapolis, Minnesota 55401, a combination electric and gas public utility company incorporated in Minnesota and an exempt public utility holding company its combination electric and gas public utility subsidiary company incorporated in Wisconsin, Northern States Power Company (''NSP–W''), 100 North Barstow Street, Eau Claire, Wisconsin 54703, and its nonutility subsidiary company, Northern Power Wisconsin Corporation incorporated in Wisconsin (''New NSP''),[1] 414 Nicollet Mall, Minneapolis, Minnesota, and Wisconsin Energy Corporation (''WEC''), an exempt public utility holding company incorporated in Wisconsin, and its combination electric and gas public utility subsidiary company incorporated in Wisconsin, Wisconsin Electric Power Company (''WEPCO''), both located at 231 West Michigan Street, Milwaukee, Wisconsin 53203 (together, ''Applicants''), have filed jointly an application-declaration under sections 2(b), 3(a)(2), 4, 5, 6(a), 7, 8, 9, 10, 11, 12(b), 13(b), 32 and 33 of the Act and rules 42, 43, 45, 81, 83, 87, 88, 90 and 91 thereunder.

The Applicants proposed to combine NSP and WEC (''Transaction'') under the Agreement and Plan of Merger, dated April 28, 1995 and amended and restated on July 26, 1995 (''Merger Agreement''). The Merger Agreement is among NSP, WEC, New NSP and WEC Sub Corp. (''WEC'' Sub'').[2] Generally, the Merger Agreement contemplates: (1) the acquisition by WEC of all of the issued and outstanding common stock of NSP; and (2) the acquisition by WEPCO of substantially all of the assets of NSP–W. Following the Transaction, WEC will be renamed Primergy Corporation (''Primergy'') and will register with the Commission under section 5 of the Act.

Applicants and Background

NSP is engaged primarily in the generation, transmission and distribution of electricity throughout a 30,000 square mile service area. NSP provides electric utility service in South Dakota and electric and gas utility service in Minnesota and North Dakota. NSP purchases, distributed and sells natural gas to retail customers, and transports customer-owned gas, in approximately 100 communities in this area. Of the more than 2.5 million people served by NSP, the majority are concentrated in the Minneapolis-St. Paul metropolitan area. As of December 31, 1995, NSP provided electric utility service to approximately 1,100,000 customers and gas utility service to approximately 330,000 customers.

NSP has seven direct wholly owned subsidiaries that are engaged in nonutility businesses. These subsidiaries are: (1) Viking Gas Transmission Company, a natural gas transmission company operating in Minnesota, Wisconsin and North Dakota; (2) Cenerprise, Inc., a natural gas and eclectic power marketing and brokering company which also provides energy conservation and management services and energy products and services and which has several energy related businesses; (3) Eloigne Company, affordable housing investment and development company which has investments in a variety of low-income housing and other projects; (4) First Midwest Auto Park, Inc., a company which owns and operates a parking garage located next to NSP's headquarters; (5) Cormorant Corporation, a company which engages in oil, gas, coal lignite and uranium exploration and the acquisition of fuel resources; (6) United Power & Land Company, a company which owns and hold, and sometimes leases, real property which is generally surrounding or adjacent to property owned and used by NSP in its regulated operations; and (7) NRG Energy, Inc., a company that develops, builds, acquires, owns and operates several non-regulated energy related businesses, owns and operates certain resource recovery businesses and steam and chilled water businesses, and through subsidiaries and affiliates, is involved in a variety of independent power projects, energy-related services and fuel enhancement and related projects and other nonutility businesses both domestic and international.

NSP–W is engaged in the generation, transmission, and distribution of electricity to: (1) Approximately 208,000 retail customers in an area of approximately 18,900 square miles in northwestern Wisconsin; (2) approximately 9,100 retail customers in an area of approximately 300 square miles in the western portion of the

[1] New NSP has no operations and exists solely to facilitate the proposed combination.

[2] WEC Sub is a Wisconsin corporation that has no operations and exists solely to facilitate the proposed combination and will not exist legally at the time of consummation of the Transaction.

Upper Peninsula of Michigan; and (3) to 10 wholesale customers in the same general area. NSP–W purchases, distributes and sells to retail customers or transports customer-owned natural gas in the same service territory to approximately 68,200 customers in Wisconsin and 4,700 customers in Michigan.

NSP–W has two wholly owned subsidiaries. These subsidiaries are Clearwater Investment, Inc., an affordable housing investment and development company which has investments in a variety of low-income housing and other projects, and NSP Lands, Inc., a company which is currently developing for sale land owned by NSP–W. It also has a 78% owned subsidiary, Chippewa & Flambeau Improvement Company, a company which builds, maintains and operates dams and reservoirs on the Chippewa and Flambeau Rivers in Wisconsin.

NSP common stock is listed on the New York Stock Exchange, Inc. (''NYSE'') and the Chicago and Pacific Stock Exchanges. As of December 31, 1995, there were 68,175,934 shares of NSP common stock and 2,400,000 shares of NSP cumulative preferred stock outstanding. NSP–W does not have any preferred stock outstanding and all of its common stock is owned by NSP. On a consolidated basis, for the year ended December 31, 1995, NSP's operating revenues were approximately $3.146 billion, of which approximately $2.401 billion were derived from electric operations, approximately $414 million from gas operations and approximately $331 million from other operations,. Also for the year ended December 31, 1995, approximately 10.2% of NSP's consolidated operating revenues were derived from nonutility businesses. In 1995, NSP–W provided approximately 15.1% of NSP's consolidated operating revenues. Consolidated assets of NSP and its subsidiaries as of December 31, 1995 were approximately $6.229 billion, consisting of $3.681 billion in net electric utility property, plant and equipment ($3.135 billion for NSP and $546 million for NSP–W); $376 million in net gas utility property, plant and equipment ($320 million for NSP and $56 million for NSP–W); and $2.172 billion in other corporate assets.

WEC, which will change its name to primer Corporation at the time of the consummation of the Transaction, has one public utility subsidiary, WEPCO. WEPCO is engaged in the business of generating, transmitting, distributing and selling electric energy to approximately 955,616 customers as of December 31, 1995. Its service area spans approximately 12,000 square miles in southeastern, including the Milwaukee area, central and northern Wisconsin and in the Upper Peninsula of Michigan and includes a population estimated at over 2,200,000. WEPCO also purchases, distributes and sells to retail customers and transports customer-owned natural gas to approximately 357,030 customers as of December 31, 1995 in three distinct service areas in Wisconsin: west and south of the City of Milwaukee, the Appleton area and the Prairie du Chien area. The gas service territory, which has an estimated population of over 1,100,000, is largely within the electric service area of WEPCO. WEPCO also distributes and sells steam supplied by its Valley Power Plant to approximately 473 space heating and processing customers (as of December 31, 1995) in downtown and near southside Milwaukee.

WEC's common stock (''Common Stock'') is listed on the NYSE. As of December 31, 1995, there were 110,819,337 shares of WEC Common Stock outstanding. WEC has no shares of preferred stock outstanding. All of WEPCO's common stock is owned by WEC. As of December 31, 1995, there were 304,508 shares of WEPCO preferred stock outstanding. WEPCO's outstanding preferred stock will not be affected by the Transaction. On a consolidated basis, for the year ended December 31, 1995, WEPC's operating revenues were approximately $1.779 billion, of which approximately $1.437 billion were derived from electric operations, approximately $318 million from gas operations, approximately $15 million from steam operations and approximately $9 million from other operations. Operating revenues from WEC's nonutility subsidiaries were approximately one-half of 1% of WEC's consolidated total operating revenues for the year ended December 31, 1995. Consolidated assets of WEC and its subsidiaries as of December 31, 1995, were approximately $4.561 billion, consisting of $3.907 billion in net electric utility property, plant and equipment, $387 million in net gas utility property, plant and equipment, $25 million in net steam utility property, plant and equipment and $242 million in nonutility assets.

WEC has seven wholly owned nonutility subsidiaries devoted primarily to stimulating economic growth in WEPCO's service area and to capitalizing on diversified investment opportunities, all of which have been formed under and pursuant to the requirements and policies of the Wisconsin Holding Company Act. These subsidiaries are: (1) Badger Service Company, a company which holds coal rights in Indiana; (2) Minergy Corp., a company engaged in the business of developing and marketing proprietary technologies designed to convert high volume industrial and municipal wastes into value-added products and which will build and operate a paper-sludge recycling facility; (3) WEC Generation International Inc., a company which will investigate investment opportunities and which has two, currently inactive, international subsidiaries; (4) Wisconsin Michigan Investment Corporation, a company which engages in investment and financing activities which include advances to affiliated companies and investments in financial instruments and partnerships developing affordable housing and other businesses; (5) WISPARK Corporation, a real estate development company which engages in all aspects of real estate development and which holds investment and ownership positions in a variety of real estate projects; (6) WISVEST Corporation, a company which invests in energy-related activities and holds investments in several energy-related companies; and (7) WITECH Corporation, a company which provides venture capital and holds equity and other positions in a variety of businesses. In addition, WEC holds a 50% interest in Custometrics LLC, a joint venture which will provide systems solutions relating to billing and other aspects of the customer service segment of the energy services industry.

Summary of Merger Related Transactions

In addition to the Transaction itself and as described more fully below as needed, the Applicants propose: (1) to form under rule 88 of the Act a new service company through Primergy's acquisition of all of the common stock of Primergy Services, Inc. (''Primergy Services'') and may form, in the same way, one or more other service companies (''Additional Service Companies''),[3] and to enter into service

[3] Primergy Services will be incorporated in Wisconsin to serve as the service company for the Primergy system. The Additional Service Companies would be known as Primergy Generation Corporation (''Primergy GC'') and Primergy Nuclear Corporation (''Primergy NC''). Primergy GC would be responsible for the operation, maintenance, repair, rehabilitation and replacement of all nonnuclear generation and steam and/or chilled water system facilities owned or operated by the system. Primergy NC would be responsible for the operation, maintenance, repair, rehabilitation and replacement of all nuclear generation facilities owned or operated by the

agreements; (2) to form a new holding company subsidiary (''Primergy Hold''), if needed, to hold, all or some of Primergy's interests in certain of its nonutility investments in existence prior to the Transaction;[4] (3) that Primergy will acquire all of the outstanding voting securities of certain NSP nonutility subsidiaries or, if Primergy Hold is not formed, all of the outstanding voting securities of all of NSP's direct nonutility subsidiaries; (4) that Primergy will retain the gas properties of NSP and WEPCO and continue their operation as combination gas and electric utilities; (5) that Primergy will retain the nonutility businesses and affiliates of NSP and WEC; (6) that Primergy will issue and/or acquire in the open market up to 18.2 million shares of its common stock (''Primergy Common Stock'') for five years from the date of an order in this matter in connection with its shareholder dividend reinvestment and stock purchase plan and its stock incentive plan; (7) to provide services at market rates, pursuant to an exemption from the at-cost standard contained in section 13(b) of the Act and provided for in rules 90 and 91, in connection with: (a) certain affiliated qualifying facilities (''QFs''), independent power projects (''IPPs''), exempt wholesale generators (EWG''), foreign utility companies (''FUCOs'') and with other associated entities presently existing or to be formed after the Transaction that derive no part of their income from the generation, transmission or distribution of electric energy for sale or the distribution of natural gas at retail in the United States (''Primergy Exempt Associate Companies''), which services may be provided by Primergy Services, the Additional Service Companies, the Primergy Exempt Associate Companies and other NSP associates and affiliates[5]; and (b) transactions approved by any state public utility regulatory agency, the Federal Energy Regulatory Commission or transactions otherwise exempted from section 13(b) requirements; (8) that all existing intra-system debt, guarantees of debt and other intrasystem transactions among NSP and WEC and their respective associated and affiliated companies be approved by the Commission[6]; and (9) that the Commission issue an order temporarily exempting New NSP from the registration requirements of section 5 of the Act for the limited time in which New NSP owns NSP–W.

The Transaction

The Transaction will be accomplished through a three-stage process. In the first state, NSP will reincorporate in Wisconsin by merging into New NSP. Immediately prior to this merger, and for state public utility regulatory purposes, NSP–W will transfer the gas utility assets necessary to furnish gas utility services to the communities of LaCrosse and Hudson, Wisconsin to New NSP (''Designated Gas Utility Assets''). In the second stage, WEC Sub will merge with and into New NSP, with New NSP left as the surviving corporation. In the third stage, NSP–W will merge into WEPCO and ownership of all other NSP subsidiaries will be transferred from NSP to Primergy. WEPCO will be then renamed Wisconsin Energy Company. Following the Transaction Primergy proposes to realign certain nonutility subsidiaries and to acquire all of the capital stock of Primergy Hold, if it is deemed necessary. Primergy Hold will serve as a holding company acquiring the capital stock of certain nonutility subsidiaries of NSP and WEC.

Specifically, the Merger Agreement provides for: (1) The merger of NSP with and into New NSP (''Reincorporation Merger'') pursuant to which (a) each issued and outstanding share of common stock, par value $2.50 per share, of NSP (''NSP Common Stock''), except shares held by NSP shareholders who perfect dissenters' rights (''NSP Dissenting Shares''), will be canceled and converted into one share of common stock, par value $2.50 per share, of New NSP (''New NSP Common Stock''), and (b) each issued and outstanding share of cumulative preferred stock, par value $100.00 per share, of NSP (''NSP Preferred Stock''), except NSP Dissenting Shares, will be cancelled and converted into one share of cumulative preferred stock, par value $100.00 per share, of New NSP (''New NSP Preferred Stock'') with terms, including dividend rates and general voting rights, and designations under New NSP's Articles of Incorporation identical to those of the canceled shares of NSP Preferred Stock under NSP's existing Restated Articles of Incorporation; and (2) the merger of WEC Sub with and into New NSP (''NSP Merger,'' together with the Reincorporation Merger, the ''Mergers'') pursuant to which (a) each issued and outstanding share of New NSP Common Stock will be canceled and converted into 1.626 (''Ratio'') shares of common stock, par value $.01 per share, of Primergy Common Stock and (b) each issued and outstanding share of New NSP Preferred Stock will remain outstanding and shall be unchanged thereby, except for any shares of New NSP Common Stock and New NSP Preferred Stock owned directly or indirectly by New NSP or WEC, which will be canceled and will not be converted or remain outstanding.

Each issued and outstanding share, par value $.01 per share, of WEC Common Stock will remain outstanding and unchanged, as one share of Primergy Common Stock. Based upon the capitalization of NSP and WEC on April 28, 1995 (the date the Merger Agreement was initially signed), and the Ratio, holders of NSP Common Stock and WEC Common Stock would each have held 50% of the aggregate number of shares of Primergy Common Stock that would have been outstanding if the Mergers had been consummated as of such date. The Applicants state that the proposed Transaction qualifies for treatment as a pooling of interests for federal income tax purposes.

Upon completion of the Transaction, Primergy will own two combination electric and gas utility companies, NSP and WEPCO. NSP will continue to operate and own the same utility facilities at the same locations outside Wisconsin as prior to the Transaction, along with the Designated Gas Utility Assets formerly owned by NSP–W. WEPCO will own and operate the same utility facilities at the same locations as prior to the Transaction, along with the balance of the gas and electric utility assets of NSP–W. The Merger Agreement provides that Primergy's principal corporate offices will be in Minneapolis, Minnesota. NSP and WEC will retain offices in Minneapolis and Milwaukee respectively as their regional headquarters. Primergy's board of directors will consist of a total of 12 directors, 6 of whom will be designated by NSP and 6 of whom will be designated by WEC.

system. The authorized capital stock of Primergy Services and any Additional Service Companies would consist of 1,000 shares of common stock, par value $.01 per share.

[4] Applicants also seek approval with regard to the issuance, sale and acquisition of the capital stock of certain of the Primergy system's approximately 16 nonutility subsidiaries in connection with the possible formation of Primergy Hold and the requisite authority to realign the nonutility companies as first-tier subsidiaries of Primergy. The authorized capital stock of Primergy Hold will consist of 1,000 shares of common stock, par value $.01 per share. Upon consummation of the Transaction, all issued and outstanding shares of Primergy Holding will be held by Primergy. If Primergy Hold is not formed, the direct nonutility subsidiaries of NSP and WEC will become direct subsidiaries of Primergy. See, SEC File No. 70–8833, Form U–1 (''Application-Declaration''), Exhibits E–12 and 13 (Primergy corporate charts with and without Primergy Hold).

[5] See, *Entergy Corporation,* Holding Co. Act Release No. 26322 (June 30, 1995).

[6] Application-Declaration at 101–03.

Services

The Applicants further request the authority to form Primergy Services and the Additional Service Companies and for them to perform services. Primergy Services and the Additional Services Companies may provide services for NSP and WEPCO, and Primergy Services may provide services for any Additional Service Companies pursuant to a service agreement and for the nonutility subsidiaries of the Primergy system pursuant to a nonutility service agreement. Such services may include any of the following: administrative, management and support services, including services relating to information systems, meters and transportation, electric and gas system maintenance, marketing and customer relations, transmission and distribution, engineering and construction, power engineering and construction, human resources, materials management, facilities, accounting, power planning, public affairs, legal, rates, finance, rights of way, internal auditing, environmental affairs, fuels, investor relations, strategic and operations planning, and general administrative and executive management services. It is anticipated that such service companies will be staffed primarily by transferring personnel from the current employee rosters of NSP, WEPCO, and their subsidiaries.

Primergy and the Additional Service Companies will record transactions using the existing data capture and accounting systems of each company. Costs will be accumulated in accounts of each service company and directly assigned, distributed and allocated to the appropriate company pursuant to the Service Agreement.

The Applicants state that the accounting and cost allocation methods and procedures of all such service companies which are formed, including Primergy Services, will comply with the Commission's standards for service companies in registered holding company systems, and that the billing systems of all such service companies, including Primergy Services, will use the Commission's ''Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies.'' Except as permitted under the Act or by the Commission, all services provided by such service companies to affiliated companies will be on an ''at cost'' basis as determined by rules 90 and 91 of the Act.

Primergy and the Additional Service Companies request that the Commission grant an exemption from the provisions of rules 90 and 91 under section 13(b) of the Act for the following transactions: (1) Services provided for EWGs, FUCOs and associate companies that derive no part of their income, directly or indirectly, from the generation, transmission or distribution of electric energy for sale, or the distribution of natural gas at retail, in the United States; and (2) services provided to an associated EWG, QF or IPP, provided that the purchaser of the electricity is not an associate company of Primergy. No services will be provided at market-based rates to an EWG, QF or IPP selling electricity to NSP or WEPCO, unless authorized by the Act or the Commission.

The Applicants request further that the Commission permit the various subsidiaries and affiliates that are providing currently services, including operation and maintenance, and selling goods to EWGs and QFs or to entities that will qualify as EWGs, FUCOs or QFs following the Transaction to continue such transactions without compliance with the at-cost provisions of section 13(b) and the rules thereunder. In addition, the Applicants request an exception regarding NSP's affiliated companies, Landfill Power LLC and Minnesota Methane LLC, that own portions of QF facilities that sell power to NSP under Public Utility Regulatory Policies Act contracts approved by the Minnesota Public Utility Commission (''MPUC'').[7]

The Applicants request further that the Commission exempt from the at-cost standards various existing contracts, which have been approved by the MPUC or the Public Service Commission of Wisconsin, among NSP and WEC affiliates that are not EWGs or QFs or entities that will become EWGs, FUCOs or QFs following the Transaction.[8] Finally, a section 13(b) exemption is requested regarding NRG Energy, Inc.'s (''NRG'') management and administrative services to be provided to O'Brien Environmental Services, Inc., which was partially acquired by NRG pursuant to a reorganization plan. The services have been approved by the bankruptcy court as part of the reorganization plan.

EUA Energy Investment Corporation (70–8837)

EUA Energy Investment Corporation (''EEIC''), P.O. Box 2333, Boston, Massachusetts 02107, a nonutility subsidiary company of Eastern Utilities Associates, a registered holding company, has filed an application-declaration under sections 6(a), 7, 9(a) and 10 of the Act and rules 45, 53 and 54 thereunder.

By orders dated December 4, 1987 and January 11, 1988 (HCAR Nos. 24525 and 24515A, respectively (''Orders''), EEIC was authorized, among other things, to conduct energy and energy conservation research and to invest, directly or indirectly in such activities.

Pursuant to the Orders, EEIC now proposes to invest through December 31, 1998, approximately $4 million to acquire approximately 1,052,630 shares of common stock of Separation Technologies, Inc. (''STI''), at a purchase price of $3.80 per share, pursuant to the terms of a stock purchase agreement (''Agreement''). STI is engaged in the research, development, design, sale, installation, construction and servicing of solid and liquid materials separation systems and facilities including, without limitation, a system for economically separating unburned carbon from coal (or fly) ash produced by utility generating plants.

EEIC will invest in STI by acquiring shares of: (1) STI's authorized but unissued common stock; and (2) a to-be-formed class of nonvoting common stock which, in all respects other than voting rights, would be identical to STI's currently authorized common stock.[9]

EEIC also requests authorization to make project financing available up to an aggregate principal amount of $15 million for the installation and construction of STI fly ash separation projects. The Agreement contains provisions granting EEIC and exclusive right of first negotiation with respect to financing all fly ash separation projects designed, sold, constructed and/or installed by STI during the eighteen month period immediately following the execution of the Agreement, excepting only financing for: (1) STI's Colbert Station project located in Alabama; and (2) any host utility financed projects.

EEIC proposes to provide such financing by entering into joint arrangements with STI at locations where STI equipment will be installed. EEIC's investment in these utility locations is anticipated to range between $0.5 and $2.5 million per installation. EEIC's investments in such future projects with STI may take the

[7] *Entergy Corporation, supra.*

[8] Application-Declaration, Annex H.

[9] As a result of the acquisition, EEIC anticipates that it will own approximately 20 percent of STI's issued and outstanding capital stock. However, EEIC states that it will only acquire a number of shares representing up to 9.9 percent of the then outstanding voting common stock of STI. In the event of an initial public offering of STI common stock, any share of nonvoting common stock acquired by EEIC would automatically convert to share of voting common stock.

form of, without limitation, joint ventures, general partnerships, limited partnerships, teaming agreements, royalties or other revenue sharing, special purpose entities, loans and equity participations.

STI has its own employees, and no employees of the EUA system retail electric utilities will be assigned to perform services for STI. EEIC does not anticipate the need to hire any additional personnel in connection with EEIC's investment in STI or the exercise of its financing rights under the Agreement.

Entergy Corporation (70–8839)

Entergy Corporation (''Entergy'' or ''Company''), 639 Loyola Avenue, New Orleans, Louisiana 70113, a registered holding company, has filed an application-declaration under sections 6(a) and 7 of the Act and rule 54 thereunder.

Entergy proposes to issue and sell through December 31, 2000, up to ten million additional shares of its authorized but unissued common stock, par value $.01 per share (''Common Stock'') pursuant to a new Dividend Reinvestment and Stock Purchase Plan ''Plan'').

The Common Stock will offered by all holders of shares of Common Stock and other interested investors (each a ''Participant'') pursuant to the Plan whereby Participants voluntarily may elect to: (1) automatically reinvest dividends received on all of their shares of Common Stock; or (2) automatically reinvest dividends received on less than all of their shares of Common Stock and continue to receive cash dividends on their remaining shares; and/or (3) invest in additional shares of Common Stock by making optional cash investments of not less than $100 nor more than $3,000 per month, with certain exceptions. Interested investors that are not shareholders may make optional cash investments in the Common Stock, but will be subject to an initial minimum investment of $1,000 and, subject to certain exceptions, a maximum of $3,000 for that month.

The shares of Common Stock purchased on behalf of the Participants to fulfill the requirements of the Plan will be in the Company's discretion, either previously issued shares purchased on the open market or in privately negotiated transactions or newly issued shares purchased directly from the Company. The decision whether to allow the Plan to purchase new but unissued shares or shares on the open market may be made by the Company only once in any three-month period.

Under the Plan, the purchase price of newly issued shares will be the weighted average of the daily high and low sales prices of the Common Stock on the New York Stock Exchange (''NYSE'') during the pricing period, which consists of the twelve trading days immediately preceding the investment date. The purchase price for shares purchased on the open market will be the weighted average price paid by the Plan including brokerage fees and commissions.

Optional cash investments in excess of $3,000 per month may be made pursuant to a waiver granted at the discretion of the Company (''Request for Waiver''). The Company has sole discretion as to whether to grant any Request for Waiver. In deciding whether to grant a Request for Waiver, the Company may consider relevant factors including, but not limited to, whether the Plan has been acquiring newly issued shares from the Company or acquiring shares in the open market or in privately negotiated transactions from third parties, the Company's need for additional capital, the attractiveness of obtaining such additional capital through a sale of Common Stock as compared to the sources of other funds, the purchase price likely to apply to a sale of the Common Stock, the Participants submitting the requests, the extent and nature of such Participants' prior participation in the Plan, the number of shares of Common Stock held of record by such Participants and the amount of their proposed investments, and the aggregate amount of optional cash investments in excess of the allowable maximum that have been submitted by all Participants. If Requests for Waiver are submitted at any time for an aggregate investment amount in excess of the amount, if any, that the Company is then willing to accept, the Company may grant such Requests for Waiver in the order of receipt, pro rata or by any other method the Company determines is appropriate.

The Company may also establish, for each monthly pricing period under the Plan, a minimum price (''Threshold Price'') applicable to the purchase of shares directly from the Company pursuant to a Request for Waiver. If established for any pricing period, the Threshold Price will be the minimum dollar amount that the average of the high and low sales prices of the Common Stock on the NYSE for each trading day of the relevant pricing period must equal or exceed. In the event the Threshold Price is not satisfied or no trades are made on the NYSE for any trading day in the pricing period, then that trading day and all trading prices for that day will be excluded in the determination of the purchase price. Additionally, for each trading day of the pricing period excluded from the pricing period, one-twelfth of the total amount of the optional cash investment of each Participant made pursuant to a Request for Waiver will be returned to that Participant without interest.

For those purchases of Common Stock made pursuant to a Request for Waiver, the Company, at least three business days prior to the first day of the applicable pricing period, may also establish a discount from the purchase price applicable to those optional cash investments (''Waiver Discount''). The Waiver Discount may be between 0% and 3% and may vary each month, but once established will apply uniformly to all optional cash investments made for that month pursuant to a Request for Waiver. The Waiver Discount will be established at the Company's total discretion after a review of current market conditions, the level of participation in the Plan and current and projected capital needs. The Company has no present plans to establish either a discount or minimum price for optional cash investments of $3,000 or less or for dividend reinvestments, but reserves the right under the Plan to do so in the future.

The Plan will be administered by Mellon Bank, N.A. or such successor administrator as Entergy may designate (''Administrator''). The Administrator will act as agent for Participants, keep records of the accounts of Participants, send regular account statements to Participants, and perform other duties relating to the Plan. Shares purchased for each Participant under the Plan will be held by and registered in the name of the Administrator or its nominee on behalf of the Participants, unless and until a Participant requests that stock certificates be issued. No service fee will be paid by Participants for shares purchased directly from the Company, but Participants will pay certain administrative fees and/or commissions on all other transactions made pursuant to the Plan.

A Participant retains all voting rights relating to shares purchased under the Plan and credited to his account, and such shares will be voted in accordance with his instructions. A Participant may withdraw from the Plan at any time upon written notice. In addition, without withdrawing from the Plan, a Participant is entitled to demand and receive a certificate representing any number of whole shares of Common Stock credited to his account. Entergy reserves the right to suspend, modify

(subject to any requisite Commission approval) or terminate the Plan at any time.

National Fuel Gas Company (70–8841)

National Fuel Gas Company (''NFG''), 10 Lafayette Square, Buffalo, New York 14203, a registered public utility holding company, has filed an application-declaration under sections 6(a), 7, 9(a), 10 and 12(c) of the Act and rules 42 and 46 thereunder.

NFG proposes to implement a sharedholder rights plan to discourage unwanted takeover bids. The Board of Directors of NFG (''Board'') proposes to declare a dividend distribution of one right (''Right'') for each outstanding share of common stock of NFG (''Common Stock''), $1.00 per value, to shareholders of record at the close of business on a record date yet to be established (''Record Date''). Each Right would entitle the registered holder to purchase from NFG one-half of one share of Common Stock at a price of $130 per share, subject to adjustment (''Purchase Price'').

Until the earliest to occur of (i) ten days following the date (''Share Acquisition Date'') of the public announcement that a person or affiliated group (''Acquiring Person'') has acquired, or obtained the right to acquire, beneficial ownership of Common Stock or other voting securities (''Voting Stock'') that have 10% or more of the voting power of the outstanding shares of Voting Stock or (ii) ten days following the commencement or announcement of an intention to make a tender offer, or exchange offer, the consummation of which would result in such person acquiring, or obtaining the right to acquire, beneficial ownership of Voting Stock having 10% or more of the voting power of the outstanding shares of Voting Stock (the earlier of such dates being called the ''Distribution Date''), the Rights will be evidenced, with respect to any shares of Common Stock outstanding as of the Record Date, by the Common Stock certificates representing those outstanding shares. Until the Distribution Date, the Rights will be transferable only with the Common Stock, and new Common Stock certificates issued after the Record Date will contain a notation incorporating the Agreement by reference. As soon as practicable following the Distribution Date, separate certificates evidencing the Rights (''Rights Certificates'') will be mailed to holders of record of Common Stock as of the close of business on the Distribution Date and such separate Right Certificates alone will evidence the Rights.

The Rights are not exercisable until the Distribution Date. As in the case with most right plans which are in place, the Rights will expire at the close of business on the tenth anniversary of the Record Date, unless earlier redeemed or exchanged by NFG as described below.

Subject to redemption or exchange of the Rights, at any time following the Distribution Date, each holder of a Right will have the right to receive, upon exercise, Common Stock (or, in certain circumstances, cash, property or other securities of NFG) having a value to two times Purchase Price of the Right then in effect. However, all Rights that are, or under certain circumstances were, beneficially owned by any Acquiring Person will be null and void.

In the vent that, at any time following the Share Acquisition Date, (i) NFG is acquired in a merger or other business combination transaction, or (ii) 50% or more of NFG's assets or earning power are sold or transferred, each holder of a Right shall thereafter have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the Purchase Price of the Right then in effect.

The Purchase Price payable, and the number of shares of Common Stock (or other securities, as the case may be) issuable upon exercise of the Rights are subject to adjustment from time to time to prevent dilution (i) in the event of a stock dividend on, or a subdivision, combination or reclassification of, the Common Stock, (ii) upon the grant to holders of the Common Stock of certain rights or warrants to subscribe for or purchase shares of the Common Stock or convertible securities at less than the then current market price of the Common Stock or (iii) upon the distribution to holders of the Common Stock of evidences of indebtedness or assets (excluding regular periodic cash dividends or dividends payable in Common Stock) or of subscription rights or warrants (other than those referred to above). Prior to the Distribution Date, the Board may make such other equitable adjustments as it deems appropriate in the circumstances in addition to or in lieu of any adjustment otherwise required by the foregoing.

With certain exceptions, no adjustment in the Purchase price will be required until the earlier of (i) three years from the date of the event giving rise to such adjustment or (ii) the time at which cumulative adjustments require an adjustment of at least 1% in such Purchase Price. No fractional shares of Common Stock will be issued and, in lieu thereof, an adjustment in cash will be made based on the market price of the Common Stock on the last trading date prior to the date of exercise.

At any time prior to 5:00 p.m. Buffalo, New York time on the tenth day following the Share Acquisition Date, NFG may redeem the Rights in whole, but not in part, at a price of $0.01 per Right (''Redemption Price''), payable in cash or stock. Under certain circumstances set forth in the Agreement, the decision to redeem shall require the concurrence of a majority of the Independence Directors. An ''Independent Director'' means any member of the Board who was a member of the Board prior to the date of the Agreement, and any person who is subsequently elected to the Board if such person is recommended or approved by a majority of the Independent Directors, but shall not include an Acquiring Person or any representative thereof. Immediately upon the action of the Board electing to redeem the Rights, NFG shall make announcement thereof and the only right of the holders of Rights will be to receive the Redemption Price.

At any time after a person becomes an Acquiring Person, the Board may exchange the Rights (other than Rights owned by an Acquiring Person, which become void), in whole or in part, at an exchange ratio of one share of Common Stock and/or other securities, cash or other assets deemed to have the same value as one share of Common Stock, per Right, subject to adjustment.

Until a Right is exercised or exchanged for Common Stock, the Rights, as such, will not grant the holders thereof rights as a stockholder of NFG. While the distribution of the Rights will not be taxable to stockholders or to NFG, stockholders may, depending upon the circumstances, recognize taxable income in the event that the Rights become exercisable for Common Stock of NFG (or other consideration) or for the stock of the Acquiring Person.

Any of the provisions of the Agreement may be amended by the Board without the consent of the holders of the Rights prior to the Distribution Date. Thereafter, the Agreement may be amended by the Board in order to cure any ambiguity, defect or inconsistency, or to make changes which do not adversely affect the interests of holders of Rights (excluding the interest of any Acquiring Person); provided, however, that no supplement or amendment may be made on or after the Distribution Date which changes those provisions relating to the principal economic terms of the

Rights. The Board may also, with the concurrence of a majority of the Independent Directors, extend the redemption period for up to an additional 20 days.

Entergy Corporation, et al. (70–8845)

Entergy Corporation (''Entergy''), 639 Loyola Avenue, New Orleans, Louisiana 70113, a registered public utility holding company, and its wholly owned subsidiary company Entergy Power, Inc. (''EPI''), 900 South Shackleford Road, Little Rock, Arkansas 72211, (both, ''Declarants''), have filed a declaration under section 12(c) of the Act and rule 46 thereunder.

EPI proposes to make one or more cash payments in an aggregate amount not to exceed $55 million to Entergy from time to time through December 31, 1998 out of EPI's unearned surplus. As of December 31, 1995, EPI had approximately $249,950,000 of capital or unearned surplus and cash and cash equivalents of approximately $59,482,000. The cash equivalents of EPI include temporary cash investments of $59,225,000, which derive from capital contributions made by Entergy to EPI in July and December 1995. Declarants state that these liquid assets are far in excess of any foreseeable capital needs of EPI. Therefore, EPI proposes to return all or most of these assets to Entergy, EPI's sole shareholder, through the proposed cash payments.

For the Commission, by the Division of Investment Management, pursuant to delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 96–11669 Filed 5–9–96; 8:45 am]

BILLING CODE 8010–01–M

[Rel. No. IC–21937; 812–9854]

Van Kampen American Capital Comstock Fund, et al.; Notice of Application

May 3, 1996.

AGENCY: Securities and Exchange Commission (''SEC'').

ACTION: Notice of Application for Exemption under the Investment Company Act of 1940 (the ''Act'').

APPLICANTS: Van Kampen American Capital Comstock Fund (''Comstock Fund''), Van Kampen American Capital Enterprise Fund (''Enterprise Fund''), Van Kampen American Capital Equity Income Fund (''Equity Income Fund''), Van Kampen American Capital Growth and Income Fund (''Growth and Income Fund''), Van Kampen American Capital Life Investment Trust on behalf of its series Common Stock Fund and Multiple Strategy Fund (''Life Trust''), Van Kampen American Capital Pace Fund (''Pace Fund''), Common Sense Trust (''Common Sense Trust'') on behalf of its series: Common Sense Growth Fund, Common Sense Growth and Income Fund, Common Sense II Growth Fund, Common Sense II Growth and Income Fund, Common Sense II International Equity Fund, Smith Barney/Travelers Series Fund, Inc. (''Smith Barney Fund'') on behalf of its series American Capital Enterprise Portfolio, Van Kampen American Capital Equity Trust (''Equity Trust'') on behalf of its series: Van Kampen American Capital Growth Fund, Van Kampen American Capital Prospector Fund, Van Kampen American Capital Value Fund (collectively, the ''Public Funds''); Van Kampen American Capital Small Capitalization Fund (''Small Cap Fund''); and Van Kampen American Capital Asset Management, Inc. (''VKACAM'') and Van Kampen American Capital Investment Advisory Corp. (''Advisory Corp.,'' together with VKACAM, the ''Advisers'').

RELEVANT ACT SECTIONS: Order requested under section 6(c) granting and exemption from section 12(d)(1), and under sections 6(c) and 17(b) granting an exemption from section 17(a).

SUMMARY OF APPLICATION; Applicants request an order amending a prior order that permits the Small Cap Fund to serve exclusively as an investment vehicle through which certain Public Funds may invest a portion of their assets in a portfolio of small capitalization stocks. The requested order would add certain parties as applicants and revise the conditions to the requested relief.

FILING DATES: The application was filed on November 17, 1995. Applicants have agreed to file an amendment during the notice period, the substance of which is included in this notice.

HEARING OR NOTIFICATION OF HEARING: An order granting the application will be issued unless the SEC orders a hearing. Interested persons may request a hearing by writing to the SEC's Secretary and serving applicants with a copy of the request, personally or by mail. Hearing requests should be received by the SEC by 5:30 p.m. on May 28, 1996, and should be accompanied by proof of service on the applicants, in the form of an affidavit or, for lawyers, a certificate of service. Hearing requests should state the nature of the writer's interest, the reason for the request, and the issues contested. Person who wish to be notified of a hearing may request notification by writing to the SEC's Secretary.

ADDRESSES: Secretary, SEC, 450 Fifth Street, N.W., Washington, D.C. 20549. Applicants: Comstock Fund, Enterprise Fund, Equity Income Fund, Growth and Income Fund, Life Trust, Peace Fund, Small Cap Fund, VKACAM, and Common Sense Trust, 2800 Post Oak Boulevard, Houston, Texas 77056; Smith Barney Fund, 388 Greenwich Street, New York, New York 10013; and Equity Trust and Advisory Corp., One Parkview Plaza, Oakbrook Terrace, Illinois 60181.

FOR FURTHER INFORMATION CONTRACT: Sarah A. Wagman, Staff Attorney, at (202) 942–0654, or Robert A. Robertson, Branch Chief, at (202) 942–0564 (Office of Investment Company Regulation, Division of Investment Management).

SUPPLEMENTARY INFORMATION: The following is a summary of the application. The complete application may be obtained for a fee at the SEC's Public Reference Branch.

Applicants' Representations

1 The Small Cap Fund is an open-end management investment company for which VKACAM serves as investment adviser. The Small Cap Fund invests at least 80% of its assets in equity securities of companies with a market capitalization less than that of the largest 500 publicly-traded companies. Although the Small Cap Fund is registered under the Act, it does not intend to make a public offering of its shares, and has not registered its shares under the Securities Act of 1933.

2. VKACAM will not charge any advisory fee for managing the Small Cap Fund, and there is no sales load or other charges associated with distribution of the Small Cap Fund's shares. The Small Cap Fund will bear the other expenses it incurs, and such expenses thus will be borne indirectly by the public Funds that invest in the Small Cap Fund.

3. The Public Funds are open-end management investment companies for which Advisory Corp. or VKACAM serves as investment companies for which Advisory Corp. or VKACAM serves as investment adviser with investment discretion over the entire portfolio. Advisory Corp. and VKACAM are both wholly-owned subsidiaries of Van Kampen American Capital, Inc. In addition to the funds named in the application, the Public Funds may include any open-end management investment company or portfolio thereof for which Advisory Corp. or VKACAM may in the future become investment

adviser with investment discretion over the entire investment portfolio.[1]

4. Limited investment in the small capitalization sector of the securities markets is an appropriate part of the investment strategy of each of the Public Funds. Under a prior order,[2] certain of the Public Funds may achieve this aspect of their investment strategy by investing in the Small Cap Fund.

The requested order would amend the prior order by adding certain parties as applicants and revising the conditions to the requested relief.

5. The Advisers believe that providing the Public Funds with a single investment vehicle to invest in a broadly diversified portfolio of small capitalization stocks will provide the Public Funds with the most effective exposure to the performance of that sector of the stock market while at the same time minimizing costs. The Small Cap Fund will hold a larger number of small capitalization issues, and thus be more diversified, than would a Public Fund if it were investing directly in small capitalization stocks. The Advisers expect that the Small Cap Fund's diversification will benefit both the Small Cap Fund and the Public Funds by providing greater price stability and lower volatility.

6. Each Public Fund may have, in addition to its holdings in the Small Cap Fund, some direct investments in small capitalization stocks. The advisers have adopted procedures to avoid the unnecessary expense that could occur if the Small Cap Fund were to sell a particular stock at the same time a Public Fund were to purchase it, or vice versa. The Small Cap Fund will circulate among the portfolio managers of the Public Funds a list of stocks it intends to purchase or sell. If any Public Fund's portfolio manager wishes to buy or sell a stock on the list, the Small Cap Fund will effect the transaction directly with that Public Fund. The value of the stock will be the current market price, determined in accordance with rule 17a–7. Payment will be made by simultaneous transfer of cash or, if the Public Fund wishes to alter its investment in the Small Cap Fund, or Small Cap Fund shares with an equal value. In cases where the payment for the subject stock is Small Cap Fund shares rather than cash, the transactions will comply with the provisions of rule 17a–7(a) through (f) in all respects other than the requirement that purchases and sales be made only for cash consideration.

7. The Advisers believe that they will be able to coordinate purchases and redemptions of Small Cap Fund shares in virtually all instances. There may be occasions, however, when a single Public Fund purchases or redeems an unusually large number of Small Cap Fund shares. Such a large transaction could cause the Small Cap Fund, and thus the Public Funds not involved in the transaction, to bear significant incremental trading costs associated with the acquisition or disposition of small capitalization stocks. Accordingly, if a Public Fund plans to make an unusually large purchase or redemption of Small Cap Fund shares, the Advisers in their sole discretion may cause the transaction to be executed in kind. In the case of a purchase, the Public Fund would acquire small capitalization stocks and exchange them for Small Cap Fund shares. For a redemption, the Small Cap Fund would deliver small capitalization stocks to the Public Fund, which the Public Fund could then sell. These redemptions will be made on a *pro rata* basis, whereby the redeeming Public Fund will receive its proportionate share of each portfolio security. Such in-kind transactions will comply with rule 17a–7(a) through (f) except that the consideration for the small capitalization stocks will be Small Cap Fund shares rather than cash.

Applicants' Legal Analysis

1. Section 12(d)(1)(A) of the Act provides that no registered investment company may acquire securities of another investment company representing more than 3% of the acquired company's outstanding voting stock, more than 5% of the acquiring company's total assets or, together with the securities of other investment companies, more than 10% of the acquiring company's total assets. Section 12(d)(1)(B) provides that no registered open-end management investment company may sell its securities to another investment company if the sale will cause the acquiring company to own more than 3% of the acquired company's voting stock, or if the sale will cause more than 10% of the acquired company's voting stock to be owned by investment companies.

2. Applicants request an exemption from section 12(d)(1) because, among other holdings, the Public Funds will own 100% of the stock of the Small Cap Fund, and a Public Fund's investment in the Small Cap fund may represent more than 5% of that Public Fund's total assets. Section 6(c) of the Act provides that the SEC may exempt persons or transactions if, and to the extent that, such exemption is necessary or appropriate in the public interest and consistent with the protection of investors and the purposes fairly intended by the policy and provisions of the Act.

Applicants request an order under section 6(c) exempting them from section 12(d)(1) (A) and (B) to permit the Public Funds to invest in shares of the Small Cap Fund in excess of the percentage limitations of section 12(d)(1).

3. Applicants believe that the proposed arrangement does not implicate the concerns underlying section 12(d)(1). For instance, because the Advisers are under common control, there will be no incentive for any Public Fund to assert undue control over the Small Cap Fund. Applicants believe that the proposed arrangement will not result in disruptive redemptions because the Advisers will coordinate the Public Funds' purchases and sales of Small Cap Fund shares to minimize the cash flow into or out of the Small Cap Fund. In addition, the Small Cap fund will not cause investors in the Public Funds to bear two layers of fees. The Small Cap Fund will pay no advisory fee, and its shares will not be subject to any sales load. Accordingly, applicants believe that the proposed arrangement meets the standards of section 6(c).

4. Applicants also request an exemption from section 17(a) of the Act, which prohibits certain purchases and sales of securities between investment companies and their affiliated persons, as defined in section 2(a)(3) of the Act. The Public Funds and the Small Cap Fund may be deemed to be under common control because each Public Fund is advised by the Advisers, and the Advisers are under the common control of Van Kampen American Capital, Inc. Each of the Public Funds and the Small Cap Fund would therefore be an affiliated person of each other within the meaning of section 2(a)(3). Thus, purchases or sales of securities between the Small Cap Fund and a Public Fund may be prohibited by section 17(a).

5. Section 17(b) of the Act provides that the SEC shall exempt a proposed transaction from section 17(a) if evidence establishes that: (a) The terms of the proposed transaction are reasonable and fair and do not involve overreaching; (b) the proposed transaction is consistent with the policies of the registered investment

[1] The Public Funds may also include other existing open-end investment management companies advised by VKACAM or Advisory Corp. that currently do not intend to rely on the requested order, but may do so in the future in accordance with the terms and conditions thereto.

[2] Investment Company Act Release Nos. 19660 (Aug. 26, 1993) (notice) and 19730 (Sept. 21, 1993) (order).

company involved; and (c) the proposed transaction is consistent with the general provisions of the Act. Applicants request an exemption under sections 6(c) and 17(b) to permit the Public Funds to purchase shares of the Small Cap Fund, and the Small Cap Fund to redeem such shares.[3] Applicants believe that the proposed transactions meet the standards of sections 6(c) and 17(b).

Applicants' Conditions

Applicants agree that any order of the SEC granting the requested relief shall be subject to the following conditions:

1. The Public Funds and the Small Cap Fund will be part of the same ''group of investment companies,'' as defined in rule 11a–3 under the Act.

2. The Small Cap Fund shall not acquire securities of any other investment company in excess of the limits contained in section 12(d)(1)(A) of the Act.

3. A majority of the trustees of the Public Funds will not be ''interested persons,'' as defined in section 2(a)(19) of the Act.

4. VKACAM will not charge any advisory fee for managing the Small cap Fund.

5. Any sales charges or service fees charged with respect to securities of the Public Funds, when aggregated with any sales charges or service fees paid by the Public Funds with respect to securities of the Small Cap Fund, shall not exceed the limits set forth in Article II, section 26, of the Rules of Fair Practice of the National Association of Securities Dealers, Inc.

6. Applicants agree to provide the following information, in electronic format, to the Chief Financial Analyst of the SEC's Division of Investment Management: monthly average total assets for each Public Fund's portfolio and the Small Cap Fund's portfolio; monthly purchases and redemptions (other than by exchange) for each Public Fund's portfolio and the Small Cap Fund's portfolio; annual expense ratios for each Public Fund's portfolio and the Small Cap fund's portfolio; and a description of any vote taken by the shareholders of the Small Cap Fund, including a statement of the percentage of votes cast for and against the proposal by the Public funds and by any other shareholders of the Small Cap Fund if any. Such information will be provided as soon as reasonably practicable following each fiscal year-end of each of the Public Funds (unless the Chief Financial Analyst shall notify applicants in writing that such information need no longer be submitted).

For the Commission, by the Division of Investment Management, under delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 96–11671 Filed 5–9–96; 8:45 am]

BILLING CODE 8010–01–M

[3] Section 17(b) applies to a specific proposed transaction, rather than an ongoing series of future transactions. *See* Keystone Custodian Funds, 21 S.E.C. 295, 298–99 (1945). Section 6(c), along with section 17(b), is frequently used to grant relief from section 17(a) to permit an ongoing series of transactions.

[Release No. 34–37169; File No. SR–NASD–96–15]

Self-Regulatory Organizations; Notice of Filing of Proposed Rule Change by National Association of Securities Dealers, Inc. Relating to Schedule A to the By-Laws To Amend the Allowable Exclusions and Deductions From the Definition of Gross Revenue for Member Assessment Purposes

May 6, 1996.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] notice is hereby given that on April 4, 1996, the National Association of Securities Dealers (''NASD'' or ''Association'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the NASD. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

Following is the text of the proposed rule change. Proposed new language is italicized; deletions are in brackets.

NASD By-Laws

Schedule A

* * * * *

Section 5 Gross Revenue for Assessment Purposes

(a) Gross revenue is defined for assessment purposes as total income as reported on FOCUS form Part II or IIA with the following exclusions:

[•] *(1)* Other income unrelated to the securities business;

[•] [Interest and dividends;]

[•] *(2)* Commodities income;

[•] *(3)* Advisory fees, investment management fees and finders' fees not directly involving the offering of securities; proxy fees; vault service fees; safekeeping fees; transfer fees; and fees for financial advisory services for municipalities;

[•] *(4)* Commissions derived from transactions executed on a registered national securities exchange or a foreign securities exchange (Note 1);

[•] *(5)* Profits or losses derived from transactions of which both the purchase and sale are executed on a registered national securities exchange, including arbitrage (Note 1); and

[•] *(6)* Profits and losses derived from transactions in certifications of deposit and commercial paper, which is defined to include drafts, bills of exchange, and bankers acceptances.

(b) In addition, members may deduct:

[•] *(1)* Any commissions, concessions or other allowances paid to another member in connection with the execution or clearance of transactions included in reported revenue. For example, a member acting as a clearing agent for another member shall deduct net amounts allowed to the non-clearing member; [and]

[•] *(2)* 25% of gross wrap fees charged to and received from customers and paid or allocated to investment managers or advisors[.]; *and*

[•] *(3) Interest and dividend expense but not in excess of related interest and dividend revenue or, alternatively, the member may deduct 40% of interest earned by the member on customer securities accounts; provided, however in addition the member may deduct the first $50,000 of net interest and dividend revenue.*

Note 1: Income not subject to exclusion for members for whom the NASD is the designated examining authority.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The self-regulatory organization has prepared summaries, set forth in Sections A, B, and C below, of the most significant aspects of such statements.

[1] 15 U.S.C. 78s(b)(1)

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

Gross revenue is defined for member assessment purposes under Section 5 of Schedule A to the NASD By-Laws (''Section 5'') as total income reported on FOCUS form Part II or IIA. Members, however, are allowed certain exclusions. Income derived from interest and dividends is currently an allowable exclusion under Section 5.

The NASD surveyed members' FOCUS filings for 1994 and conducted discussions with a number of member firm representatives, from which the NASD determined that, along with the normal interest income from customer margin accounts and interest and dividends from trading and investment positions, a significant portion of interest revenue for certain members is associated with the member's trading strategies involving, for example, repurchase, reverse repurchase, and stock loan/borrow transactions, which are considered over-the-counter revenues from the securities business.

The NASD is proposing to amend Section 5 of Schedule A by deleting a provision which currently allows a member to exclude its interest and dividends from gross revenue for assessment purposes. The proposed rule change, however, would add a new provision to allow a member to deduct from gross revenue for assessment purposes either: (i) its interest and dividend expenses but not in excess of related interest and dividend revenue; or, alternatively, (ii) 40% of interest earned by the member on customer securities accounts. The first deduction is intended to allow the member to subtract directly-related expenses from interest and dividend revenue to be included in the definition of gross revenue. The alternative deduction is intended to eliminate the potential for inequitable allocation of assessments on those members whose interest and dividend revenue is obtained without significant expenses related to trading strategies, (*e.g.*, if a member derives interest revenue primarily from margin accounts and finances this lending through its own capital). It would also be consistent with the assessment of interest and dividend revenue by the Securities Investor Protection Corporation (''SIPC''), which permits an alternative offset to gross interest and dividend revenue consisting of 40% of interest earned on customer securities accounts. The proposed rule change, in addition, would allow a member to deduct from its gross revenue the first $50,000 of net interest and dividend revenue in order to continue to encourage the accumulation of net capital, particularly by smaller members.

Based on NASD data, the NASD estimates that the proposed rule change, if adopted for 1995, would have generated assessment revenue of $3 million based on the budgeted level of assessment revenue of $39 million for that year.

The proposed rule change would also amend Section 5 to provide alphabetical references to its two primary subsections and by replacing all bullets referencing its secondary subsections with numerical references.

The NASD is proposing that the proposed rule change take effect for the 1996 assessment based on revenues generated in calendar year 1995.

2. Statutory Basis

The NASD believes that the proposed rule change is consistent with the provisions of Section 15A(b)(5) of the Act[2] which requires that the rules of the association provide for the equitable allocation of reasonable dues, fees and other charges among members in that the proposed rule change would recognize interest and dividend revenue as a part of a member's gross revenue for assessment purposes, while recognizing that expenses incurred in connection with such interest and dividend revenue should be allowed to be deducted from such revenue (*e.g.* as part of ''matched transactions''). It would also allow members whose business incurs less direct expense in connection with interest and dividend revenue to alternatively deduct 40% of interest earned by the member on customer securities accounts. It would, in addition, allow members to deduct from their gross revenue the first $50,000 of net interest and dividend revenue for assessment purposes in order to continue to encourage the accumulation of net capital. The proposed rule change also would be consistent with the SIPC's assessment of such revenue.

B. Self-Regulatory Organization's Statement on Burden on Competition

The NASD published for comment in Notice to Members 95–94 (October 27, 1995) (''NTM 95–94'') a proposal to include net interest and dividends in the definition of gross revenue for assessment purposes under Section 5.[3] One commentor argued that the proposed rule change contained in NTM 95–94 discriminates against fixed income firms which finance mostly liquid collateral (*i.e.*, governments and mortgages) and will make the small, match-book spreads of these firms even smaller, thereby forcing certain firms to move their match-book business and proprietary trading accounts to a non-regulated entity. The commentor also argued that the proposed rule change would be unfair to small members whose ratio of ''other qualified revenue'' to ''revenue from sales of shares'' may be higher than large companies. The NASD modified the proposed rule change published for comment to address such concerns by allowing a member to choose from one of two alternative deductions relating to its interest and dividend revenue and, in addition, to deduct from its gross revenue the first $50,000 of net interest and dividend revenue.

Based on the foregoing, the NASD does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act, as amended.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Twenty comment letters were received in response to NTM 95–94.[4] Of the twenty commentors, four commentors supported but expressed certain concerns, and sixteen opposed the proposed rule change. The commentors are referenced by the number attached to their comment letter in the list of comment letters attached at Exhibit 3.

1. Definition of Non-Securities Business Revenue

Commentors (Nos. 1, 4, 11, 13, and 14) argue that dividends from a member's pure investment account are not revenue generated from the securities business but the fruit of hard work from previous years. The NASD believes that a member's proprietary investment account is retained business capital maintained to generate gross revenue for the member's securities business. Such proprietary accounts play an integral part in the member's securities business and are subject to NASD regulatory oversight. Revenue from such proprietary accounts are part of the member's securities business and,

[2] 15 U.S.C. 78o–3.

[3] A copy of NTM 95–54 was submitted as Exhibit 2 to the NASD's proposal and is available for inspection and copying in the Commission's Public Reference Room.

[4] Copies of the comment letters were submitted as Exhibit 3 to the NASD's proposal and are available for inspection and copying in the Commission's Public Reference Room.

therefore, are appropriate for inclusion in the definition of gross revenue for assessment purposes.

One insurance commentor (No. 12) argues that it should only be assessed for interest and dividend revenue relating to the interest and dividends attributable to the capital necessary to operate its securities business. The NASD's position is that an insurance company's interest and dividend revenue from its insurance business will not be included in the definition of gross revenue for assessment purposes.

2. Effect on Net Capital

Commentors (Nos. 1, 3, 4, 11 and 20) argue that the NTM 95–94 proposal would discourage members from accumulating passive investments that increase the firm's net capital and protect public investors. The NASD amended the proposed rule change contained in NTM 95–94 to address such concerns by allowing a member to deduct from its gross revenue the first $50,000 of net interest and dividend revenue in addition to allowing the member to deduct one of two other alternative deductions provided by the proposed rule change.

3. Equitable Allocation of Dues, Fees and Assessments

NTM 95–94 stated that the proposed rule change was partially intended to fund the increased costs associated with implementing the recommendations of the Rudman Committee. Commentors (Nos. 1, 10, 12 and 19) argue that the proposed rule change inequitably allocates the regulatory costs resulting from the Rudman Committee recommendations to firms with significant passive investments which are not used by such firms in their securities business. One commentor recommends that, in order to equitably allocate such Rudman Committee related-costs, the NASD should determine the interest assessment on a firm-by-firm basis by considering such factors as the firm's standing with the NASD, the historical audit performance, the risks and liquidity associated with a firm's trading and collateral positions, whether or not a firm has significant customer or institutional business, and the firm's credit and risk management policies.

The NASD notes that the proposed rule change is only partially intended to fund certain Rudman recommendations and its overall intent is to fund the NASD's broader regulatory budget requirements. The NASD believes that using gross revenue for assessment purposes has historically provided for the equitable allocation of reasonable assessments among members. The proposed rule change's inclusion of interest and dividends from retained capital and certain trading situations in the definition of gross revenue is appropriate because the NASD is required to oversee the related-securities activity. The proposed rule change, therefore, is part of the same assessment approach that has historically been followed by the NASD and the securities industry. The proposed rule change, as already noted, would also be consistent with current SIPC assessment provisions. The NASD, therefore, believes that the members' arguments for changing the basis of such assessments are not justified.

4. Discrimination Against Certain Members

As previously noted, one commentor (No. 10) argues that the proposed rule change contained in NTM 95–94 discriminates against fixed income firms which finance mostly liquid collateral (*i.e.*, governments and mortgages) and will make the small, match-book spreads of these firms even smaller, thereby forcing certain firms to move their match-book business and proprietary trading accounts to a non-regulated entity. The commentor also argues that it would be unfair to small members whose ratio of ''other qualified revenue'' to ''revenue from sales of shares'' is higher than large companies. The NASD has modified the proposed rule change published for comment to address such concerns by allowing a member to deduct from its gross revenue the first $50,000 of net interest and dividend revenue in addition to allowing the member to deduct one of two other alternative deductions provided by the proposed rule change.

The NASD further believes that a member could not use a non-regulated entity to handle its U.S. match-book business because this would subject such an entity to registration as a broker/dealer under Section 15 of the Act. This would also be true for the handling of the member's proprietary trading accounts.

5. Clearing Capital

Commentors (No. 6, 8, and 15) expressed concerns regarding potential assessments on their clearing capital. Two commentors (6 and 8) argue that members that put up clearing capital to be in business should not be assessed on the interest on this capital, or alternatively assessed only on yearly income above some amount, perhaps $100,000. One commentor (No. 15) only supports the proposed rule change because it believes its security deposits with clearing brokers would be exempt. It is the position of the NASD that a member's clearing capital serves the function of capital in any business, *i.e.*, to run the business and increase gross revenue for the business. Further, the requirements for clearing capital are subject to NASD regulatory oversight and, therefore, justified for inclusion in gross revenue for assessment purposes. The NASD, however, has amended the proposed rule change contained in NTM 95–94 to allow a member to deduct from its gross revenue the first $50,000 of net interest and dividend revenue in order to address the concerns of smaller members regarding this matter.

6. NASD Assessment Discounts

One Commentor (No. 19) argues that the NASD currently ''discounts'' member assessments, presumably because the current system, without change, already provides more funds than is necessary for operations. The commentor, therefore, argues that the NASD does not need a new funding category. The NASD believes that its practice of discounting member assessments provides the NASD with the flexibility to equitably return to its members a portion of assessments during business cycles wherein the aggregate gross revenue of the securities industry is normal or better, while ensuring the NASD with sufficient funds to meet the regulatory mandates of the Act during business cycles in which gross revenue of the securities industry has significantly decreased. This practice of discounting member assessments has proven to be an effective funding method for oversight of the securities industry and, therefore, has proven itself to be an important part of the investor protections provided by the NASD to the securities markets. In addition, the NASD's definition of gross revenue for assessment purposes should equitably include all categories of revenue from a member's securities business. The NASD believes that the inclusion of net interest and dividend revenue from the member's retained capital and trading strategies, in the definition of gross revenue for assessment purposes, is appropriate in assessing all gross revenue from the securities business regulated by the NASD.

7. NASD SIPC Rationale

One commentor (No. 19) argues that the administrative and compliance activity of the NASD is separated too far in its nature from the insurance activity of the SIPC to provide a compelling argument that NASD's fund raising be consistent with SIPC. The NASD notes

that in further conforming its assessment policy to SIPC's, the Association is not intending to imply that its business is equivalent to SIPC's, but rather that the proposed rule change is based on assessment policy that has already been found to be an equitable allocation of reasonable assessments among members of the securities industry.

8. Net Interest Revenue Derived From Exchange-Listed Securities

One commentor (No. 7) states that a substantial amount of its net interest revenue is derived from margin loans secured by exchange-listed securities and securities lending activities involving exchange-listed securities. The commentor notes that Schedule A, Section 5 of the NASD By-Laws excludes income from the sale of exchange-listed securities, and therefore, argues that net interest revenue from such exchange listed securities should also be excluded. The commentor also notes that it would be extremely difficult, if not impossible, to break out net interest revenue as to its source of origin, *i.e.,* exchange versus non-exchange securities. The NASD believes that interest derived from margin loans and securities lending activities, involving exchange-listed securities or customer accounts including such securities, does not itself represent an exchange transaction but rather a regulated over-the-counter transaction. Such non-exchange activity is significantly different than the current Section 5 exclusion from gross revenue regarding member commissions, trading or investment gains derived from transactions executed on a registered national securities exchange or a foreign securities exchange. The NASD also acknowledges and agrees with the impracticality of segregating such income between exchange and non-exchange business.

9. Request for NASD Audited Annual Financial Income Statement and Balance Sheet/Simplified Revenues Assessment

Two commentors (Nos. 2 and 5) argue that the NASD should provide a detailed accounting to demonstrate the need for additional revenues. One commentor (No. 2) argues for an audited annual financial income statement and balance sheet of the NASD corporate body to erase misperceptions that a surplus may already exist. The NASD, in response to the first comment, notes that an audited financial accounting of the association's activities is provided annually to the membership and the interested public in the organization's annual report. With respect to the second comment, the NASD maintains a level of working capital and equity which is prudent in its business judgment in order to ensure that the NASD is able to fulfill its regulatory mandates.

One commentor (No. 2) argues that if the need for additional assessment revenues exists, then the additional revenues can be obtained ''by simply increasing the current assessment by 7.7%.'' The NASD believes it is more appropriate and equitable to include interest and dividends revenue in gross revenue as provided by the proposed rule change before increasing the assessment percentage on gross revenue for all members. The NASD believes that the proposed rule change enhances the equitable allocation of assessments by adding certain interest and dividend revenue derived from retained capital and certain trading practices to the definition of gross revenue for assessment purposes.

A commentor (No. 5) argues that if the need for additional revenue is shown to be temporary, then the assessment should be temporary. The NASD does not intend the proposed rule change to be temporary and notes that the purpose of the proposed rule change is to meet ongoing budgetary requirements.

10. Member Vote

One commenter (No. 1) argues that the inclusion of any new revenue category should be subject to membership vote. The NASD notes that Article VI, Section1 of the By-Laws permits the Board of Governors to make changes in member assessments without recourse to the membership for approval. This provision of the By-Laws was adopted by the Board of Governors and approved by the Commission as an appropriate regulatory function of the NASD under the Act. The proposed rule change is, however, subject to publication for comment by the SEC and the SEC will exercise its independent review function in determining whether to approve or disapprove the proposed rule change.

11. Other Comments

Four commentors (Nos. 9, 16, 17, and 18) supported the proposed rule change contained in NTW 95–94 as providing more consistent treatment of net interest and dividend revenue. The commentors argue, however, that since additional revenue will be received by the NASD under the proposed rule change, an offset should take place through a reduction in other member charges. They argue that the proposed rule change comes at a time when firms are looking to eliminate costs, increase efficiency and protect capital. Another commentor (No. 3) argues that the NASD should attempt to meet its budgetary challenges as its membership is doing, *i.e.,* investigating more efficient ways of accomplishing objectives and cutting costs. The NASD concurs with the latter commentor and continues to address budgetary challenges by increasing the efficiency of oversight of the broker/dealer industry. However, increased efficiencies of NASD operations alone, as suggested by the former commentors, do not meet the budgetary challenges required to fund the commitment of greater resources to the NASD's broker/dealer regulation activities in compliance with the regulatory mandate of the Act, as amended.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 35 days of the date of publication of this notice in the Federal Register or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

A. By order approve such proposed rule change, or

B. Institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, N.W., Washington, D.C. 20549. Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying to the Commission's Public Reference Room. Copies of such filing will also be available for inspection and copying at the principal office of the NASD. All submissions should refer to the file number in the caption above and should be submitted by May 31, 1996.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority, 17 CFR 200.30–(a)(12).

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 96–11747 Filed 5–9–96; 8:45 am]

BILLING CODE 8010–01–M

DEPARTMENT OF STATE

[Public Notice No. 2375]

Shipping Coordinating Committee, Subcommittee on Safety of Life at Sea Working Group on Fire Protection; Notice of Meeting

The U.S. Safety of Life at Sea (SOLAS) Working Group on Fire Protection will conduct an open meeting on May 29, 1996, at 9:30 AM, in Room 4315, at U.S. Coast guard Headquarters, 2100 Second Street SW., Washington, DC 20593. The purpose of the meeting will be to prepare for discussions anticipated to take place at the Forty-first Session of the International Maritime Organization's Subcommittee on Fire Protection, scheduled for September 30, 1996.

The meeting will focus on proposed amendments to the 1974 SOLAS Convention for the fire safety of commercial vessels. Specific discussion areas include: the new mandatory Fire Test Procedures Code, proposed restructuring of Chapter II–2, halon fire extinguishing systems, emergency escape breathing devices, fire-retardant materials for fishing vessel lifeboats, criteria for maximum fire loads, fire safety measures for deep fat cooking equipment, interpretations to SOLAS 74, role of the human element in maritime casualties, safety of passenger submersible craft, recognition of test laboratories, fixed fire detection and alarm systems for new and existing cargo ships, and shipboard safety emergency plans.

Interested members of the public are encouraged to attend. For further information regarding the meeting of the SOLAS Working Group on Fire Protection contact Mr. Jack Booth at (202) 267–2997.

Dated: May 1, 1996.

Charles A. Mast,

Chairman, Shipping Coordinating Committee.

[FR Doc. 96–11804 Filed 5–9–96; 8:45 am]

BILLING CODE 4710–07–M

DEPARTMENT OF TRANSPORTATION

Reports, Forms and Recordkeeping Requirements; Agency Information Collection Activity Under OMB Review

AGENCY: Department of Transportation (DOT), Federal Aviation Administration.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this notice announces that the Information Collection Request (ICR) abstracted below has been forwarded to the Office of Management and Budget (OMB) for review and comment. The FAA requested and received an emergency clearance through June 30, 1996 under OMB control number 2120–0595. This request is for the three year clearance. The ICR describes the nature of the information collection and its expected cost and burden.

DATES: Comments must be submitted by June 7, 1996.

FOR FURTHER INFORMATION CONTACT: FAA Hotline number (202) 267–7029, or the Internet Home Page: http://www.faa.gov/asu/asu100/acq-reform/acq__home.htm.

SUPPLEMENTARY INFORMATION:

Title: Federal Aviation Administration Acquisition Management System (FAAMS).

Abstract: This document contains policy guidance that implements the FY 1996 Transportation Appropriation Bill, that gave FAA an exemption from acquisition laws and provided authority to create a flexible, more cost effective system. Guidance is focused on the acquisition management system, the life cycle acquisition process, the procurement system and process, and an acquisition work force learning system Acquisitions are handled by integrated product teams who provide support through all stages of the process.

Need: Pursuant to section 348 of Public Law 104–50, the FAA hereby develops and implements a new acquisition management system that addresses the unique needs of the agency. This document establishes the policies, guiding principles, and internal procedures for FAA's new acquisition system.

Respondents: The respondents are individuals and businesses who do or wish to do business under contract with the FAA. We estimate approximately 3,300 respondents.

Frequency: The frequency is on occasion and monthly with an estimated 1 to 12 responses per respondent.

Burden: The estimated burden is 333,292 hours annually. Comments on this collection should be submitted to the Office of Information and Regulatory Affairs, OMB, New Executive Office Bldg., 725 17th St. NW., Washington, DC 20503, Attention: Desk Officer for FAA.

Issued in Washington, D.C. on May 7, 1996.

Phillip A. Leach,

Clearance Officer, United States Department of Transportation.

[FR Doc. 96–11787 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–13–P

Coast Guard

[CGD 96–019]

Waterfront Facilities; Marine Transportation Related Pipeline Testing

AGENCY: Coast Guard, DOT.

ACTION: Request for comments.

SUMMARY: The Coast Guard is conducting a study to evaluate several alternative methods, in addition to those presently approved, for testing marine transfer pipelines on facilities capable of transferring oil or hazardous material, in bulk, to or from a vessel with a capacity of 250 barrels or more. These methods may provide suitable alternatives for facility operators while maintaining an equivalent level of safety.

DATES: Comments must be received on or before July 9, 1996.

ADDRESSES: Comments may be mailed to Commandant (G–MCO–3), Port and Facilities Compliance Branch, 2100 Second Street, SW, Washington, DC 20593–0001.

FOR FURTHER INFORMATION CONTACT: Lieutenant (junior grade) David Deaver, Port and Facilities Compliance Branch, Commandant (G–MCO–3), room 1104, (202) 267–0502, between 7 a.m. and 3 p.m., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION: The Coast Guard is responsible for ensuring compliance for marine transportation related (MTR) facilities, including requirements for transfer pipeline systems. The scope of this study concerns possible testing alternatives for the transfer pipeline system from the dock loading arm or manifold of the Coast Guard inspected MTR facility up to the first valve encountered after the pipe enters the Spill Prevention Control and Countermeasure (SPCC) area or the first valve encountered after the pipe enters the secondary containment

around the bulk storage tank for facilities not protected by SPCC plans.

Present regulations require that transfer pipelines be hydrostatically tested at 1.5 times the maximum allowable working pressure (MAWP) on an annual basis. In August of 1994, the Coast Guard also established guidelines for conducting pneumatic pressure testing as an alternative method. In addition, the Coast Guard has become aware of other, non-destructive testing methods, including acoustic and ultrasonic methods through several alternative requests submitted by industry and discussions with the Office of Pipeline Safety.

The Coast Guard is evaluating these other testing options to assess their suitability as alternative pipeline testing methods for facility operators while maintaining an equivalent level of safety. To accomplish this, Coast Guard is seeking comments on the following issues pertaining to the use of alternative methods for ensuring pipeline safety: (1) Whether using methods other than pressure testing would provide the same or greater level of confidence for ensuring that a pipeline meets safety standards; (2) Whether companies would apply to use other programs, to include using methods such as ultrasonic and acoustic testing, as alternatives to pressure testing; and, (3) Whether use of alternative testing methods would be physically practical and less costly than current requirements. In addition to these, the Coast Guard encourages the submission of comments regarding any other aspects of its pipeline inspection policy.

Dated: May 6, 1996.

J.C. Card,

Rear Admiral, U.S. Coast Guard, Chief, Marine Safety And Environmental Protection.

[FR Doc. 96–11775 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–14–M

Federal Aviation Administration

[Docket No. 28567]

A Call for the Development of Prototype(s) for a Global Analysis and Information Network (GAIN)

AGENCY: Federal Aviation Administration, DOT.

ACTION: Notice; request for comments.

SUMMARY: David Hinson, Administrator of the Federal Aviation Administration (FAA), stresses that Zero Accidents is the only acceptable safety goal for the aviation industry and the FAA. This notice offers some ideas for the elements needed to establish an early warning capability for existing and emerging safety concerns that would move the aviation industry towards Zero Accidents, and challenges the aviation industry to participate in developing that capability. Because of an emerging combination of improved cooperation between airline management, labor, and various governments, advancements in information technologies, and the political environment in several countries, the international aviation industry has an unprecedented opportunity, by sharing and analyzing aviation safety information, to reach Zero Accidents.

This notice (a) solicits comments on the Global Analysis and Information Network (GAIN) concept and implementation strategy for collecting and analyzing aviation safety data, and (b) invites participation in the development of proof-of-concept prototypes. All interested parties, whether or not in the aviation community, are invited to comment on the ideas presented, offer alternative solutions, indicate interest in helping to develop a GAIN prototype or the overall system itself, and comment about how government aviation safety agencies can best help the industry reach Zero Accidents.

DATES: Comments in response to this call for action must be received by June 14, 1996.

ADDRESSES: It is requested that *all* comments be submitted via the Internet by sending an e-mail message with your comments (plain text preferred, no graphics please) to: concept __paper@asyweb01.nasdac.faa.gov.

Please include your name and organization. Comments must also be mailed in hard-copy (two copies) via regular mail to: Federal Aviation Administration, 800 Independence Ave., SW., Office of Chief Counsel, Attention: Rules Docket (AGC–200), Docket No. 28567, Washington, DC 20591.

All comments must be marked: ''Docket No. 28567.'' Commenters wishing the FAA to acknowledge receipt of their comments must include a pre-addressed, stamped postcard on which the following statement is made: ''Comments to Docket No. 28567.'' The postcard will be date stamped and mailed to the commenter.

Comments submitted about this Notice may be examined at the FAA at the above address in room 915G on weekdays, except on Federal holidays, between 8:30 a.m. and 5:00 p.m. In addition, commenters will be able to review all other comments by Internet. Your submission should not contain any proprietary or other information that you do not want to be made available to the public.

FOR FURTHER INFORMATION CONTACT: Mr. Chuck Fluet, Manager, Safety Analysis Division, Office of Aviation Safety, ASY–200, Federal Aviation Administration, 400 7th Street, SW., Washington, DC 20590, telephone 202–267–GAIN (202–267–4246).

SUPPLEMENTARY INFORMATION: The aviation industry has made remarkable progress in reducing aviation accident rates. With today's volume of flights, the industry would have suffered *more than 10,000 fatalities* last year worldwide if the accident rate had not improved so dramatically since 1960. Because of this major decline in the accident rate, the industry now suffers an average of *less than 800 fatalities* worldwide per year. However, the rate has remained stubbornly consistent for about the last 10 years; and at today's accident rate, forecast growth in air transportation demand will lead to *more than 4,500 fatalities* worldwide per year by 2025—clearly an unacceptable result.

Sound methods for certifying the safety of new aviation products and procedures, as well as surveillance activities that help to ensure safe operation and maintenance of these products and procedures, have contributed significantly to the current safety levels of the aviation industry. Within the framework of these regulatory methods, technological advances in engine performance and reliability, airframes and materials, air traffic control, cockpit automation, and simulator training have contributed to the safety of the aviation system. Compliance inspections, accident and incident investigations, special studies, and program evaluations are the fundamental methods of continuing surveillance in the operating environment, and safety has improved significantly over the years in part because of the lessons learned by using these methods to understand the mistakes and oversights of the past.

Yet all too often, the industry has not been able to use data about accidents, incidents and other system anomalies to become aware of existing or emerging safety problems in time to take preventive measures. Just as traditional product design and manufacturing methods eventually gave way to new, improved principles and methods, a new safety information paradigm, with much greater sensitivity to anomalies in daily aviation system operations, could help the industry reach Zero Accidents. Just as aviation product improvements

of the past have been fostered by technological advances, improvements in aviation safety monitoring and alerting will become possible as a result of major advances in information management technology.

An Outline of a New Safety Monitoring Paradigm

The industry must develop a significantly improved operational early warning capability that is sensitive enough to detect and alert the aviation community to existing and emerging problems. A major aspect of this capability is the *sharing of safety information,* both *within* categories in the industry, e.g., carriers must share with other carriers and manufacturers with other manufacturers; and *across* categories, e.g., labor, management, carriers, manufacturers, air traffic controllers, airport operators, and others must share with each other. Creating useful information, however, generally requires the collection of large amounts of data, and it also involves the careful analysis of that data. Rarely would there be any need or desire to share any raw data, but the sharing of the *analysis* of the data—the information—could be mutually beneficial. Gathering and analyzing large amounts of qualitative and quantitative aviation safety data to better understand routine system operations is the foundation of the Global Analysis and Information Network (GAIN) concept.

The GAIN system would be more sensitive to conditions that signal increased safety risks because it would contain information about normal aviation system operations. The statistical baseline for normal aviation operations, constructed with digital flight and ATC radar data, among other major and currently untapped sources, would be the plumb line from which deviations are measured. The importance of obtaining information about a far greater percentage of aircraft operations has been illustrated repeatedly by all-too-typical accident investigation findings of earlier flights that experienced problems similar to the accident aircraft. A truly effective early warning capability would involve significant improvements in information feedback and analysis for aviation operations. At a minimum, the GAIN concept would add the following new elements to the existing monitoring systems to improve sensitivity:

—New data sources *that would improve risk assessment and provide a baseline for normal flight operations, thus improving the chances of early anomaly detection.*

—New and innovative data management and analytical techniques and methodologies *that quickly reveal obscure and/or infrequent data patterns and associations.*

—New methods to *disseminate the findings quickly and globally to all who could use them to improve aviation safety.*

Analytical Strategies and Automated Tools

The proposed analysis process would be based upon new sources of information and new information technology capabilities. First, information from voluntary reporting programs (such as the confidential Aviation Safety Reporting System (ASRS), or the Air Safety Reports (ASR) used by certain airlines) and mandatory incident reporting systems (such as the Pilot Deviation or Runway Incursion data bases) would be subjected to a range of analysis tools. These include advanced data pattern searches—which can be performed autonomously on the data by ''intelligent agent'' automation tools to discover patterns or associations, finding the ''needle in the haystack.'' ''Intelligent agent'' software would aid analysts in discovering thematic associations in text data bases, and data visualization tools would show the analyst associations in data base elements. Application of such data mining analysis tools would provide a more focused understanding of operational safety concerns much sooner than current analysis techniques. The data management and analysis take place in a ''data warehouse'' where operational data are extracted from existing systems and, through a series of steps that standardize and improve the quality of the data, the data are transformed into a data base designed for targeted analysis. Within a ''data warehouse'' environment, safety analysts can employ various data mining strategies.

Once existing or emerging safety concerns are identified, hypotheses that are developed to explain them can be tested using empirical digital flight data, ATC radar data, or other appropriate data sources. A focus on remedial measures would at times result from an analysis of digital flight data or ATC automated data, both vast sources of empirical data.

As a result of new information technologies, we have the capability, for the first time, to monitor and analyze the parameters of safe and normal flight. Until very recently, it has been very difficult to obtain accurate and reliable information on normal flight operations. Now, thanks to new computer technologies, we can use flight data recorder and radar information to generate large amounts of very accurate and detailed information about flight performance. For example, the Boeing 777 records information on 700 flight parameters 8 times a second. Several countries, mostly in Europe, have programs in which a carrier or civil aviation agency routinely monitors and analyzes operational data captured on flight data recorders.

Statistical analysis of digital data or ATC automated data from normal flights would yield a baseline of routine operations that can be used to detect variations from norms. In addition, baseline statistics would help safety analysts quantify operating risks within, as well as beyond, the envelope of normal operations. By collecting and analyzing information primarily about what went wrong, we are missing the opportunity to learn what was done right to avoid an accident or incident in earlier situations. The likelihood of detecting problems and developing remedies is significantly greater from studying large numbers of normal daily operations than from relying primarily upon a far smaller number of periodic inspections or accident and incident investigations.

Analysis of digital flight data can provide several types of information, including aircraft path analysis, derivation of environmental conditions, aircraft configuration time histories, aerodynamic coefficients (analysis of coefficients can reveal degradation in aerodynamic performance), engine performance, aircraft attitude, automated flight control modes and status, warning parameters, takeoff and landing distances, and flight loads. Digital flight data can be used to detect single anomalies—alerting operators when criteria values for selected parameters have been exceeded or when particular events occur. Such data also can be used to develop descriptive statistics across fleets, to detect deviations from statistical norms in the aviation system, or to measure the effects of design, procedure, or equipment changes.

ATC automated data could be used to analyze airplane motion and relative position, important factors in analyzing issues such as wake vortex and environmental effects. An analysis of air traffic control automated data for normal operations could provide insight into methods for improving ATC system operations or potential problem areas. Flight data anomalies from accidents could be compared to similar anomalies of flights that did not crash to learn what was done differently to avoid an

accident. These findings might suggest guidelines on pilot training or aircraft design. The same autonomous ''intelligent agent'' analysis techniques used to find patterns in data from incident reporting also can be applied to digital flight data and ATC radar data—or information derived from this data such as paths, flight loads, or aerodynamic coefficients—to determine if any otherwise unobserved associations exist within the data.

Human Factors Analysis

This analytical process and the new sources of data under consideration could significantly improve our ability to describe what is happening in the aviation system, and a comparable human factors analysis capability must also be developed. Without a reliable human factors analysis tool that addresses the underlying causes or factors associated with emerging safety concerns, remedial measures may only be temporary ''band aids.'' An effective human performance analysis capability developed for use on digital flight data or ATC automated data—augmented by feedback from voluntary disclosure systems—is an essential part of an early warning system.

A Proposed Architecture for Sharing

As noted above, for a number of reasons, not the least of which is the very large quantity of data, there will probably be little or no sharing of raw data, but only of information from the analysis of data. Moreover, because of improved networking technologies and capabilities, information would not necessarily all be sent to a massive computer at one location, but would probably be available to different users to different extents by networking—sometimes known as a ''virtual database.'' For example, this networking capability makes it possible for each carrier, manufacturer, or union to have separate GAIN-type systems, or they could do it collectively with one or more others or through trade associations, or any combination of them, and the information sharing could occur over the network to the extent desired or permitted by the owner of each system.

The information that results from GAIN analyses would ideally be available immediately to all recipients who could use it to improve aviation safety. The dissemination of vital information can be accomplished with existing infrastructure—using the Internet, for example, if adequate safeguards can be provided to protect the security and confidentiality concerns of the information providers regarding identified or identifiable data. The GAIN network would have to accommodate different requirements in a user-friendly way, and be able to notify automatically all appropriate recipients about potential problems without requiring them to know to query the system.

Examples of Proactive Use of Aviation Safety Data

There are several examples in various countries that demonstrate how effectively proactive safety measures can be implemented as a result of industry/labor/government partnership sharing of such information. When one air carrier's data indicated that pilots were frequently disregarding their Ground Proximity Warning System (GPWS), the carrier discovered that the frequent disregard was due to a high false alarm rate, and further analysis of the data provided the basis for developing a software remedy. As a result, that GPWS system was improved (to the benefit of *all* carriers that used it), the false alarm rate dropped, and pilots ignored the warning much less.

Similarly, a carrier that was experiencing frequent altitude capture excursions and deviations in one of its aircraft types found from the data that the problem was a combination of inadequate pilot training and poor altitude capture logic. Analysis of the data provided the basis for improving both the training and the logic. Again, the logic fix benefited *all* users of that autopilot around the world, not just the carrier that discovered the problem.

Other examples include improvements to training programs and/or operations manuals as a result of high pitch angle takeoffs, more rapid that desirable takeoff rotation rates, inadvertent flap/slat retraction out of the proper speed range, and unstabilized approaches; design fixes for equipment that did not perform as designed or anticipated (e.g., an aircraft that was developing cracks from hard landings at less than the 2 g cutoff beyond which inspection was mandated); and improvements in airport signs and markings to help pilots more accurately follow their taxi clearances.

Also important, of course, is that without the data, it is very difficult for carriers, manufacturers, or governments to *evaluate* whether new programs and other fixes are having the desired result.

Concept Implementation Issues

Collection and Analysis of Aviation Safety Data

In *developing* an analytical process for an early warning capability that would monitor the system and alert the aviation community to existing and emerging safety concerns, please consider what data requirements, analysis methods, and information dissemination methods you would propose. In relation to the analytical process, please consider and comment on issues such as the following:

— What aviation safety data and information are needed to support your analysis plan and what, of those needs, is not now being collected?
—Should large quantities of data be collected on a wide range of safety issues, or less data on fewer targeted safety issues?
—To what extent is standardization of the data collection or of analysis techniques necessary? How should the necessary standardization be accomplished?
—How could existing data, such as information from voluntary reporting and correction, ASRS, AQP, FOQA, and other such programs, be analyzed better to provide meaningful and useful information?
—What could industry and government do to improve existing means for data collection?
—Are incentives needed to stimulate the submission of information that is not derived from accidents or incidents, as opposed to merely removing the disincentives, in order to encourage reporting?
—To what extent can international information sharing occur with a ''virtual database'' instead of a physically centralized data base?
—What techniques and capabilities are you aware of in the aviation industry or in other industries to analyze data effectively and generate statistically significant results, with predictive value, from large quantities of data describing normal operations?
—What analytical techniques and capabilities are you aware of in the aviation industry or in other industries to respond effectively to the myriad of human factors issues that arise in operational monitoring analysis?

Dissemination of Aviation Safety Information

—To what extent are security measures needed, and what security measures are available, to protect information confidentiality while still assuring that it reaches all in the industry who could use it to improve aviation safety?
—What alerting methods are available to ensure that information is automatically distributed to all recipients who could use it to

improve aviation safety without their having to know to ask?

General

—Will an analysis and dissemination system such as GAIN help the aviation industry reach Zero Accidents?
—Are there better ways to help the industry reach Zero Accidents?
—What concerns, if any, do you have about the existence of an analysis and dissemination system such as GAIN?
—What should the relationship be between government regulators and GAIN for it to be most effective ?
—Although commercial aviation is the initial target for this effort, how can other sectors of the aviation industry, including the military, help with this initial effort?
—How can the program be expanded to include input from, and the development of remedies in relation to information provided by, manufacturing personnel, mechanics, flight attendants, dispatchers, ramp personnel, and other aviation industry professionals whose input could help with the proactive effort?

Considerations for Developing Prototypes

General

Ultimately GAIN could develop into a comprehensive international network of systems for analysis and sharing of aviation safety information. However, that development would have to occur incrementally, starting with one or more prototypes of various pieces of the network. Among the areas that should be evaluated from prototype development are: international data standardization, data collection protocols, analytical methods, data sharing, alerting mechanisms, and the potential value of emerging technologies. By prototyping key elements of GAIN, it will be possible to obtain operational proof of the most significant new capabilities being incorporated in this early warning system. With a minimal initial commitment of resources, risks and costs would be reduced, while allowing the overall operational feasibility of the concept to be assessed. It would help define obstacles and issues associated with the development of GAIN, and provide valuable information for future implementation planning. Because more types of data, more types of analyses, and more users should not generally be added unless experience demonstrates that such additions would be useful, prototypes would help to provide the experience to determine the desirability of such additions.

Ownership

For several reasons, the elements of the GAIN network should probably not be owned or operated by the FAA or the aviation regulatory agency of any other country. Instead, they should probably be owned by those members of the international aviation industry that benefit economically from its successful performance, analogous to existing collectively-owned, non-profit joint ventures in the aviation industry that provide services for the owners' mutual benefit. There are several reasons for pursuing this type of ownership. First, GAIN would probably enjoy better acceptance by the industry if it is not viewed as a government effort to gather information for enforcement purposes or to protect its own manufacturers and carriers in an international marketplace. Second, private ownership, as compared with governmental ownership, would facilitate protecting sensitive information from public disclosure. Third, the funding of GAIN should not depend upon the fiscal situation in any one country.

Last, but not least, GAIN's existence would be most assured, and it would perform most effectively and efficiently, if it were owned jointly by those who have a direct economic interest in its success—namely, the insurers, manufacturers, carriers, pilots, mechanics, controllers, and airport operators that make up the industry. Either GAIN *will* improve aviation safety and substantially reduce costs for the entire industry—because prevention costs less than accidents—in which event industry will want to own and operate it; or it will not accomplish these goals, in which event a better way must be developed to reach Zero Accidents.

In determining how GAIN might be owned and structured, we invite your comment about:

—What types of prototypes could best demonstrate the concept at the lowest cost, given existing data collection and analysis techniques and capabilities?
—What entities could help develop prototype projects, how much would they cost, and what sources of funding are available?
—What role can you play in the prototyping effort and subsequent efforts to develop an operational GAIN?

The Role of the FAA

The FAA is already engaged in several activities to demonstrate, in relatively small scale, the utility of safety data collection and analysis, but the GAIN network and its prototypes would probably not be FAA systems. The FAA's Office of System Safety could help facilitate the creation of GAIN by informing potential participants about the concept, and by bringing potential participants together, but the FAA will not own or operate GAIN, and will probably not fund its development. Instead, the FAA would be one of many users of the analytical results and supporting data from GAIN.

Given the numerous proactive accident prevention activities that are already underway in various countries, it is likely that the aviation industry would eventually develop an international cooperative data sharing system, such as the GAIN network, on its own. The problem has been that it is difficult for any one profession, manufacturer, or airline to develop a program that systematically facilitates international sharing of information to the benefit of the entire international aviation community. Thus, in addition to facilitating this development by demonstrating its intent to cooperate more with industry to reach Zero Accidents, the FAA can play a major role in accelerating the progress of private industry by bringing together the entities that can help to develop GAIN prototypes—preferably by building as much as possible upon the systems that are already in place rather than starting anew—and by helping to assure that the prototypes are sufficiently standardized and consistent to work together in the more comprehensive GAIN network as it ultimately develops.

Conclusion: A Call To Action

Please let us know of your ideas regarding the development of a GAIN network, particularly regarding how you can become involved, either in a GAIN prototype or in the more comprehensive permanent effort. This is not an invitation for bids or a request for proposals, but we are soliciting indications of interest, as well as input regarding the viability of this or any other concept to help the industry reach Zero Accidents.

You are encouraged to review the comments (Commenters will be able to review all other comments by Internet) and be creative about how you, individually or together with other commenters, can begin the development of GAIN prototypes. If warranted by the nature and extent of the comments, the FAA will host a conference to bring interested parties together to discuss refinements of the GAIN concept and the development of prototypes.

Issued in Washington, D.C., on May 7, 1996.

Christopher A. Hart,

Assistant Administrator for System Safety, Federal Aviation Administration.

[FR Doc. 96–11725 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–13–P

Notice of Intent To Rule on Application to Use the Revenue From a Passenger Facility Charge (PFC) at Detroit Metropolitan Wayne County Airport and Willow Run Airport, Detroit, Michigan

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of Intent to Rule on Application.

SUMMARY: The FAA proposes to rule and invites public comment on the application to use the revenue from a PFC at Detroit Metropolitan Wayne County Airport and Willow Run Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Public Law 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

DATES: Comments must be received on or before June 10, 1996.

ADDRESSES: Comments on this application may be mailed or delivered in triplicate to the FAA at the following address:

Federal Aviation Administration, Detroit Airports District Office, Willow Run Airport, East, 8820 Beck Road Belleville, Michigan 48111.

In addition, one copy of any comments submitted to the FAA must be mailed or delivered to Robert C. Braun, Director of Airports of the Detroit Metropolitan Wayne County Airport at the following address: Detroit Metropolitan Wayne County Airport, Mezzanine, L.C. Smith Terminal, Detroit, MI 48242.

Air carriers and foreign air carriers may submit copies of written comments previously provided to the Detroit Metropolitan Wayne County Airport under section 158.23 of Part 158.

FOR FURTHER INFORMATION CONTACT: Mr. Leonard Mizerowski, Program Manager, Federal Aviation Administration, Detroit Airports District Office, Willow Run Airport, East, 8820 Beck Road, Belleville, Michigan 48111 (313–487–7277). The application may be reviewed in person at this same location.

SUPPLEMENTARY INFORMATION: The FAA proposes to rule and invites public comment on the application to use the revenue from a PFC at Detroit Metropolitan Wayne County Airport and Willow Run Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Public Law 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

On April 15, 1996, the FAA determined that the application to use the revenue from a PFC submitted by Detroit Metropolitan Wayne County Airport substantially complete within the requirements of section 158.25 of Part 158. The FAA will approve or disapprove the application, in whole or in part, no later than August 8, 1996.

The following is a brief overview of the application.

PFC Application No.: 96–02–C–00–DTW.

Level of the PFC: $3.00.

Actual charge effective date: January 1, 1993.

Estimated charge expiration date: June 21, 2009.

Total approved net PFC revenue: $640,707,000.00.

Brief description of proposed project(s):

Detroit Metropolitan Wayne County Airport

Land Acquisition and Preliminary Design for Fourth Parallel Runway.

Willow Run Airport

Perimeter Property Fencing and Removal of Airport Hazards Class or classes of air carriers which the public agency has requested not be required to collect PFCs: FAR Part 158.23 air taxi/commercial operators (ATCOs) filing from 1800–31 and enplaning fewer than 500 passengers per year at the airport.

Any person may inspect the application in person at the FAA office listed above under **FOR FURTHER INFORMATION CONTACT.**

In addition, any person may, upon request, inspect the application, notice and other documents germane to the application in person at the Detroit Metropolitan Wayne County Airport.

Issued in Des Plaines, Illinois, on May 3, 1996.

Benito DeLeon,

Manager, Planning/Programming Branch, Airports Division, Great Lakes Region.

[FR Doc. 96–11730 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–13–M

Notice of Intent To Rule on Application to Use the Revenue From a Passenger Facility Charge (PFC) at Ford Airport, Iron Mountain, Michigan

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of Intent to Rule on Application.

SUMMARY: The FAA proposes to rule and invites public comment on the application to use the revenue from a PFC at Ford Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Public Law 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

DATES: Comments must be received on or before June 10, 1996.

ADDRESSES: Comments on this application may be mailed or delivered in triplicate to the FAA at the following address:

Federal Aviation Administration, Detroit Airports District Office, Willow Run Airport, East, 8820 Beck Road, Belleville, Michigan 48111.

In addition, one copy of any comments submitted to the FAA must be mailed or delivered to Mr. William H. Marchetti, Airport Manager, of the Dickinson County Board of Commissioners, at the following address: County Courthouse 701 Stevenson Avenue, P.O. Box 609, Iron Mountain, MI 49802.

Air carriers and foreign air carriers may submit copies of written comments previously provided to the Dickinson County Board of Commissioners, under Section 158.23 of Part 158.

FOR FURTHER INFORMATION CONTACT: Mr. Jon Gilbert, Program Manager, Federal Aviation Administration, Detroit Airports District Office, Willow Run Airport, East, 8820 Beck Road, Belleville, Michigan 48111 (313–487–7281). The application may be reviewed in person at this same location.

SUPPLEMENTARY INFORMATION: The FAA proposes to rule and invites public comment on the application to use the revenue from a PFC at Ford Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Public Law 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

On April 23, 1996, the FAA determined that the application to use the revenue from a PFC submitted by the Dickinson County Board of Commissioners was substantially complete within the requirements of Section 158.25 of Part 158. The FAA will approve or disapprove the application, in whole or in part, no later than July 9, 1996.

The following is a brief overview of the application.

PFC Application No.: 96–02–U–00–IMT.

Level of the PFC: $3.00.

Actual charge effective date: June 1, 1995.

Estimated charge expiration date: December 31, 1998.

Total approved net PFC revenue: $215,820.00.

Brief description of proposed projects: Install sanitary sewer; rehabilitate Runway 1/19, including HIRL and signs; install PAPI and REIL's (Runway 19); construct and light Taxiway ''H'', GA apron and GA access road.

Class of classes or air carriers which the public agency has requested not be required to collect PFCs: Not applicable.

Any person may inspect the application in person at the FAA office listed above under **FOR FURTHER INFORMATION CONTACT.**

In addition, any person may, upon request, inspect the application, notice and other documents germane to the application in person at the Dickinson County Board of Commissioners.

Issued in Des Plaines, Illinois, on May 3, 1996.

Benito DeLeon,

Manager, Planning/Programming Branch, Airports Division, Great Lakes Region.

[FR Doc. 96–11731 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–13–M

Notice of Intent To Rule on Application to Impose and Use the Revenue From a Passenger Facility Charge (PFC) at Marquette County Airport, Marquette, Michigan

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of Intent to Rule on Application.

SUMMARY: The FAA proposes to rule and invites public comment on the application to impose and use the revenue from a PFC at Marquette County Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Public Law 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

DATES: Comments must be received on or before June 10, 1996.

ADDRESSES: Comments on this application may be mailed or delivered in triplicate to the FAA at the following address:

Federal Aviation Administration, Detroit Airports District Office, Willow Run Airport, East, 8820 Beck Road, Belleville, MI 48111.

In addition, one copy of any comments submitted to the FAA must be mailed or delivered to Mr. Harold R. Pawley, Airport Manager, of the Marquette County Airport at the following address: Marquette County Airport, 198–B Airport Road, Negaunee, MI 49866–9669.

Air carriers and foreign air carriers may submit copies of written comments previously provided to the Marquette County Airport under Section 158.23 of Part 158.

FOR FURTHER INFORMATION CONTACT: Mr. Jon Gilbert, Program Manager, Federal Aviation Administration, Detroit Airports District Office, Willow Run Airport, East, 8820 Beck Road, Belleville, Michigan 48111 (313–487–7281). The application may be reviewed in person at this same location.

SUPPLEMENTARY INFORMATION: The FAA proposes to rule and invites public comment on the application to impose and use the revenue from a PFC at Marquette County Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Public Law 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

On April 23, 1996, the FAA determined that the application to impose and use the revenue from a PFC submitted by Marquette County Airport was substantially complete within the requirements of section 158.25 of Part 158. The FAA will approve or disapprove the application, in whole or in part, no later than July 9, 1996.

The following is a brief overview of the application.

PFC Application No.: 96–03–C–00–MQT.

Level of the proposed PFC: $3.00.

Proposed charge effective date: July 1, 1996.

Proposed charge expiration date: September 1, 1996.

Total estimated PFC revenue: $32,500.00.

Brief description of proposed project(s): Purchase snow removal equipment.

Class or classes of air carriers which the public agency has requested not be required to collect PFC's: Air taxis and charters.

Any person may inspect the application in person at the FAA office listed above under **FOR FURTHER INFORMATION CONTACT**.

In addition, any person may, upon request, inspect the application, notice and other documents germane to the application in person at the County of Marquette, Michigan.

Issued in Des Plaines, Illinois, on May 3, 1996.

Benito DeLeon,

Manager, Planning/Programming Branch, Airports Division, Great Lakes Region.

[FR Doc. 96–11732 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–13–M

Federal Highway Administration

Supplemental Environmental Impact Statement: Lane County, Oregon

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice of intent to supplement a final environmental impact statement.

SUMMARY: The FHWA is issuing this notice to advise all concerned that a supplement to the final environmental impact statement will be prepared for the West 11th Street-Garfield Street, Florence-Eugene Highway (known locally as the West Eugene Parkway) in Lane County, Oregon.

FOR FURTHER INFORMATION CONTACT: Elton Chang, Environmental Engineer, Federal Highway Administration, 530 Center Street N.E., Room 100, Salem, Oregon, 97301, Telephone: (503) 399–5749, Fax (503) 399–5838.

SUPPLEMENTARY INFORMATION: The FHWA, in cooperation with the Oregon Department of Transportation and the City of Eugene Public Works Department will prepare a supplement to the final environmental impact statement (FEIS) on the proposal to construct an approximately 9.3 kilometers (5.8 miles) east-west thoroughfare as an extension of the 6th and 7th couplet on a new alignment in the City of Eugene. The original FEIS (FHWA–OR–EIS–85–05–F) for this roadway was approved on November 20, 1989 and the Record of Decision (ROD) signed on April 4, 1990. The final EIS followed a draft EIS dated October 3, 1985 and a supplemental draft EIS dated June 5, 1986. All three environmental documents were reviewed by the public and interested agencies. The new roadway would start in the east at Garfield Street and the 6th and 7th Streets couplet near Highway 99W and terminate in the west with a connection to Route 126 approximately 1.1 kilometers (0.7 miles) west of the Oak Hill railroad overpass in Lane County, Oregon. In general, the new roadway would have four 3.6-meter (12-foot) wide travel lanes and a parkway-type design that would include a 4.3-meter (14-foot) wide landscaped median with 1.2-meter (4-foot) inside shoulders for both roadways, and 2.4-meter (8-foot) wide shoulder/bike lanes on the

outside of the travel lanes. This roadway is an important linkage between Highway 126 in the west and I–105/I–5 in east Eugene. The need for an east-west limited access thoroughfare has been documented in land use and transportation plans since 1959 to serve the existing and projected traffic demand resulting from the growth projected in the industrial development of west Eugene. In addition, the parkway would serve the growth in residential development in the Bethel-Danebo Neighborhood to the north of the proposed roadway. Since the approval of the final EIS and the selection of Alternative 1 (Modified) for design and the signing of the ROD in 1990, additional coordination and consultation have been done with environmental agencies to avoid and minimize project impacts to rare, threatened and endangered species and their habitats found in the project area. As a result of this consultation, a design modification has been proposed for the western 5.2 kilometers (3.25 miles) of the adopted project (slightly east of Terry Street to Highway 126). The approved design for the West Eugene Parkway (WEP) that was south of and parallel to the Southern Pacific railroad line is proposed to be shifted north of and parallel to the railroad. Initial analysis (October 1994) of the northern design option has found that there would be less direct impacts on the Willamette Valley wet prairie wetlands, a rare habitat type, and the direct impacts to the Western pond turtles, a sensitive species, would be eliminated.

In addition, recent traffic analysis from the City of Eugene has shown that projected traffic for local streets, Highway 99W and the eastern portion of the WEP can best be served by a minor design modification in the intersection with Highway 99W and the approved project. The northbound 99W connection to the westbound new WEP is now proposed to be made by an elevated structure rather than at grade to maintain an acceptable level-of-service. These two minor design modifications are being proposed to the approved project to further reduce the impacts found in the final EIS. The impacts of the modifications will be examined in greater detail in the proposed supplemental EIS.

Newsletters describing the proposed action and soliciting comments will be sent to appropriate Federal, State and local agencies, and to private organizations and citizens who have previously expressed or are known to have an interest in this proposal. Two public meetings will be held in Eugene during May/June, 1996 to identify issues that should be addressed and an additional meeting will be held during the summer to describe preliminary findings of the technical studies. In addition, a public hearing will be held following the distribution of the draft supplemental EIS for public and agency review. Public notice will be given of the times and places of all meetings and hearings. No formal scoping meeting will be held. To ensure that the full range of issues related to this proposed action are addressed and all significant issues identified, comments and suggestions are invited from all interested parties. Comments or questions concerning this proposed action and the supplemental EIS should be directed to the FHWA at the address provided above.

(Catalog of Federal Domestic Assistance Program Number 20.205, Highway Research, Planning and Construction. The regulations implementing Executive Order 12372 regarding intergovernmental consultation on Federal Programs and activities apply to this program.)

Issued on: May 1, 1996.

Elton Chang,

Environmental Engineer, Federal Highway Administration.

[FR Doc. 96–11657 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–22–M

National Highway Traffic Safety Administration

[NHTSA Docket No. 96–042–No1]

Motor Vehicle Occupant Safety Survey (II)

AGENCY: National Highway Traffic Safety Administration, DOT.

ACTION: Notice and request for comments on data collection.

SUMMARY: NHTSA's purpose in conducting this survey is to assist the Agency in fulfilling its Congressional mandate to reduce the injuries, fatalities, and economic loss resulting from motor vehicle crashes. There is overwhelming evidence that the regular and proper use of safety devices such as safety belts, child safety seats, and helmets is effective in reducing injuries and fatalities in vehicle crashes. It is, therefore, important that effective strategies be developed to promote the use of such devices. To understand how best to encourage use of these safety devices, NHTSA needs up-to-date information on the patterns of their use and reasons for non-use by the public. By collecting these data, NHTSA will be able to determine where its efforts should be targeted and where new strategies may be needed.

DATES: Written comments must be submitted on or before June 28, 1996.

ADDRESSES: Direct all written comments to National Highway Traffic Safety Administration, Docket Section, Room 5111, Docket # 96–042–No1, 400 Seventh Street, S.W., Washington, D.C. 20590.

FOR FURTHER INFORMATION CONTACT: Mr. Alan Block, Contracting Officer's Technical Representative, Office of Program Development and Evaluation (NTS–31), National Highway Traffic Safety Administration, 400 Seventh Street, S.W., Room 6240, Washington, D.C. 20590.

SUPPLEMENTARY INFORMATION:

I. Abstract

The National Highway Traffic Safety Administration (NHTSA) was established to reduce the mounting number of deaths, injuries and economic losses resulting from motor vehicle crashes on the Nation's highways. As part of this statutory mandate, NHTSA is authorized to conduct research as a foundation for the development of motor vehicle standards and traffic safety programs.

During the late 1960s and early 1970s, more than 50,000 persons were killed each year in motor vehicle crashes in the United States. Diverse approaches were taken to address the problem. Vehicle safety designs and features were improved; restraint devices were improved; safety behaviors were mandated in state legislation (including safety belt use, child safety seat use, and motorcycle helmet use); alcohol-related legislation was enacted; this legislation was enforced; public information and education activities were widely implemented; and roadways were improved.

As a result of these interventions and improvements, crash fatalities dropped significantly. By 1994, total fatalities had fallen to 40,676, representing a 20% decline from 1966. In addition, the resident population and the number of vehicle miles traveled increased greatly over the past 25 years. When fatality rates are computed per 100,000 population, the rate for 1994 (15.62) was more than 40 percent lower than the 1966 rate (26.02). In sum, heightened highway safety activity conducted over the past two decades corresponds with major strides in reducing traffic fatalities.

Remaining barriers to safety will be more resistant to programmatic influences now that the easy gains have already been accomplished. Up-to-date information is essential to plot the direction of future activity that will

achieve the more difficult gains in the coming years.

In order to collect the critical information needed by NHTSA to develop and implement effective countermeasures that meet the Agency's mandate to improve highway traffic safety, NHTSA conducted its first Motor Vehicle Occupant Safety Survey in 1994. The survey included questions related to safety belts, child safety seats, airbags, bicyclist safety, pedestrian safety, motorcyclist safety, and Emergency Medical Services. It also contained small segments on alcohol use and on speeding.

The proposed survey is the second Motor Vehicle Occupant Safety Survey. The survey will collect data on topics included in the first (1994) survey and will monitor changes over time in the use of occupant protection measures and in attitudes related to vehicle occupant safety. It is important that NHTSA monitor these changes so that the Agency can determine the effects of its efforts to promote the use of safety devices and to identify areas where its efforts should be targeted and where new strategies may be needed. NHTSA is also exploring some additional topics related to issues identified since the previous survey, particularly regarding airbags and children, that have important public safety implications.

II. Method of Data Collection

The survey will be conducted by telephone among a national probability sample of 8,000 adults (age 16 and older). Participation by respondents is voluntary. NHTSA's information needs require safety belt and child safety seat sections too large to merge into a single survey instrument without producing an inordinate burden on respondents. Rather than reduce these sections, the survey instrument will be divided into two series of modules. Each module will be administered to one-half the total number of subjects to be interviewed. Module Series #1 of the questionnaire will focus on safety belts and include smaller sections on airbags, motorcyclist safety, general driving (including speed), and crash experience. Module Series #2 will focus on child safety seats, accompanied by smaller sections on bicyclist safety and Emergency Medical Services. Both series will contain sections on drinking and driving because of the extensive impact of alcohol on the highway safety problem. Some basic safety belt questions contained in Module Series #1 will be duplicated on Module Series #2. (Some topics may be changed from one series to the other in the final questionnaires.)

The interviewers will use computer-assisted telephone interviewing to reduce interview length and minimize recording errors. A Spanish-language translation and bilingual interviewers will be used to minimize language barriers to participation. The survey will be anonymous and confidential.

III. Use of Findings

The findings of this study will assist NHTSA in addressing the problem of motor vehicle occupant safety and in formulating programs and recommendations to Congress. NHTSA will use the findings to: (a) Identify areas to target current programs and activities to achieve the greatest benefit; (b) develop new programs and initiatives aimed at increasing the use of occupant safety devices by the general public; and (c) provide informational support to States and localities in their traffic safety efforts. The findings will also be used directly by State and local highway safety and law enforcement agencies in the development and implementation of effective countermeasures to prevent injuries and fatalities to vehicle occupants.

IV. Data

OMB Number: None
Form Number: None
Type of Review: Regular Submission
Affected Public: The population of the United States age 16 and older living in households with telephones.
Estimated Number of Respondents: 8000
Estimated Time Per Respondent: 20 minutes
Estimated Total Burden: 2667 hours
Estimated Total Cost: $46.97 per survey respondent

V. Requests for Comments

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden (including the hours and cost) of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Comments submitted in response to this notice will be summarized and/or included in the request for approval by the Office of Management and Budget (OMB) of this information collection. Copies of all comments will be placed in Docket 96–042, Notice 1, in the NHTSA Docket Section in Room 5109, Nassif Building, 400 7th Street, S.W., Washington, D.C. 20590, and will become a matter of public record.

James H. Hedlund,

Associate Administrator for Traffic Safety Programs.

[FR Doc. 96–11748 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–59–P

[Docket No. 96–14; Notice 2]

Decision That Nonconforming 1992 Through 1996 Mercedes-Benz Gelaendewagen Type 463 Long Wheel Base V–8 Multi-Purpose Passenger Vehicles Are Eligible for Importation

AGENCY: National Highway Traffic Safety Administration (NHTSA), DOT.

ACTION: Notice of decision by NHTSA that nonconforming 1992 through 1996 Mercedes-Benz Gelaendewagen Type 463 Long Wheel Base V–8 multi-purpose passenger vehicles (MPVs) are eligible for importation.

SUMMARY: This notice announces the decision by NHTSA that 1992 through 1996 Mercedes-Benz Gelaendewagen Type 463 Long Wheel Base V–8 MPVs not originally manufactured to comply with all applicable Federal motor vehicle safety standards are eligible for importation into the United States because they have safety features that comply with, or are capable of being altered to comply with, all such standards.

DATES: The decision is effective May 10, 1996.

FOR FURTHER INFORMATION CONTACT: George Entwistle, Office of Vehicle Safety Compliance, NHTSA (202–366–5306).

SUPPLEMENTARY INFORMATION:

Background

Under 49 U.S.C. 30141(a)(1)(A) (formerly section 108(c)(3)(A)(i)(I) of the National Traffic and Motor Vehicle Safety Act (the Act)), a motor vehicle that was not originally manufactured to conform to all applicable Federal motor vehicle safety standards shall be refused admission into the United States unless NHTSA has decided that the motor vehicle is substantially similar to a motor vehicle originally manufactured for importation into and sale in the United States, certified under 49 U.S.C. 30115 (formerly section 114 of the Act), and of the same model year as the model of the motor vehicle to be compared, and is capable of being readily altered to conform to all

applicable Federal motor vehicle safety standards. Where there is no substantially similar U.S.—certified motor vehicle, 49 U.S.C. 30141(a)(1)(B) (formerly section 108(c)(3)(A)(i)(II) of the Act, 15 U.S.C. 1397(c)(3)(A)(i)(II)) permits a nonconforming motor vehicle to be admitted into the United States if its safety features comply with, or are capable of being altered to comply with, all applicable Federal motor vehicle safety standards based on destructive test data or such other evidence as NHTSA decides to be adequate.

Petitions for eligibility decisions may be submitted by either manufacturers or importers who have registered with NHTSA pursuant to 49 CFR Part 592. As specified in 49 CFR 593.7, NHTSA publishes notice in the Federal Register of each petition that it receives, and affords interested persons an opportunity to comment on the petition. At the close of the comment period, NHTSA decides, on the basis of the petition and any comments that it has received, whether the vehicle is eligible for importation. The agency then publishes this determination in the Federal Register.

Europa International, Inc. of Santa Fe, New Mexico (Registered Importer No. R–91–002) petitioned NHTSA to decide whether 1992 through 1996 Mercedes-Benz Gelaendewagen Type 463 Long Wheel Base V–8 MPVs are eligible for importation into the United States. NHTSA published notice of the petition on February 21, 1996 (61 FR 6684) to afford an opportunity for public comment. The reader is referred to that notice for a thorough description of the petition. No comments were received in response to the notice. Based on its review of the information submitted by the petitioner, NHTSA has decided to grant the petition.

Vehicle Eligibility Number for Subject Vehicles

The importer of a vehicle admissible under any final determination must indicate on the form HS–7 accompanying entry the appropriate vehicle eligibility number indicating that the vehicle is eligible for entry. VCP–13 is the vehicle eligibility number assigned to vehicles admissible under this determination.

Final Decision

Accordingly, on the basis of the foregoing, NHTSA hereby decides that 1992 through 1996 Mercedes-Benz Gelaendewagen Type 463 Long Wheel Base V–8 MPVs are eligible for importation into the United States because they have safety features that comply with, or are capable of being altered to comply with, all applicable Federal motor vehicle safety standards.

Authority: 49 U.S.C. 30141(a)(1)(B) and (b)(1); 49 CFR 593.8; delegations of authority at 49 CFR 1.50 and 501.8.

Issued on: May 7, 1996.

Marilynne Jacobs,

Director, Office of Vehicle Safety Compliance.

[FR Doc. 96–11784 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–59–M

[Docket No. 96–045; Notice 1]

Notice of Receipt of Petition for Decision That Nonconforming 1992 Jeep Cherokee Multi-Purpose Passenger Vehicles Are Eligible for Importation

AGENCY: National Highway Traffic Safety Administration, DOT.

ACTION: Notice of receipt of petition for decision that nonconforming 1992 Jeep Cherokee multipurpose passenger vehicles (MPVs) manufactured for the Venezuelan market are eligible for importation.

SUMMARY: This notice announces receipt by the National Highway Traffic Safety Administration (NHTSA) of a petition for a decision that a 1992 Jeep Cherokee that was manufactured for the Venezuelan market and not originally manufactured to comply with all applicable Federal motor vehicle safety standards is eligible for importation into the United States because (1) it is substantially similar to a vehicle that was originally manufactured for sale in the United States and that was certified by its manufacturer as complying with the safety standards, and (2) it is capable of being readily altered to conform to the standards.

DATES: The closing date for comments on the petition is June 10, 1996.

ADDRESSES: Comments should refer to the docket number and notice number, and be submitted to: Docket Section, Room 5109, National Highway Traffic Safety Administration, 400 Seventh St., SW, Washington, DC 20590. [Docket hours are from 9:30 am to 4 pm]

FOR FURTHER INFORMATION CONTACT: George Entwistle, Office of Vehicle Safety Compliance, NHTSA (202–366–5306).

SUPPLEMENTARY INFORMATION:

Background

Under 49 U.S.C. § 30141(a)(1)(A) (formerly section 108(c)(3)(A)(i)(I) of the National Traffic and Motor Vehicle Safety Act (the Act)), a motor vehicle that was not originally manufactured to conform to all applicable Federal motor vehicle safety standards shall be refused admission into the United States unless NHTSA has decided that the motor vehicle is substantially similar to a motor vehicle originally manufactured for importation into and sale in the United States, certified under 49 U.S.C. § 30115 (formerly section 114 of the Act), and of the same model year as the model of the motor vehicle to be compared, and is capable of being readily altered to conform to all applicable Federal motor vehicle safety standards.

Petitions for eligibility decisions may be submitted by either manufacturers or importers who have registered with NHTSA pursuant to 49 CFR Part 592. As specified in 49 CFR 593.7, NHTSA publishes notice in the Federal Register of each petition that it receives, and affords interested persons an opportunity to comment on the petition. At the close of the comment period, NHTSA decides, on the basis of the petition and any comments that it has received, whether the vehicle is eligible for importation. The agency then publishes this decision in the Federal Register.

Champagne Imports, Inc. of Lansdale, Pennsylvania (''Champagne'') (Registered Importer 90–009) has petitioned NHTSA to decide whether 1992 Jeep Cherokee MPVs manufactured for the Venezuelan market are eligible for importation into the United States. The vehicle which Champagne believes is substantially similar is the 1992 Jeep Cherokee that was manufactured for sale in the United States and certified by its manufacturer as conforming to all applicable Federal motor vehicle safety standards.

The petitioner claims that it carefully compared the non-U.S. certified 1992 Jeep Cherokee to its U.S. certified counterpart, and found the two vehicles to be substantially similar with respect to compliance with most Federal motor vehicle safety standards.

Champagne submitted information with its petition intended to demonstrate that the non-U.S. certified 1992 Jeep Cherokee, as originally manufactured, conforms to many Federal motor vehicle safety standards in the same manner as its U.S. certified counterpart, or is capable of being readily altered to conform to those standards.

Specifically, the petitioner claims that the non-U.S. certified 1992 Jeep Cherokee is identical to its U.S. certified counterpart with respect to compliance with Standards Nos. 102 *Transmission Shift Lever Sequence* * * *., 103 *Defrosting and Defogging Systems,* 104 *Windshield Wiping and Washing*

Systems, 105 *Hydraulic Brake Systems,* 106 *Brake Hoses,* 107 *Reflecting Surfaces,* 109 *New Pneumatic Tires,* 113 *Hood Latch Systems,* 116 *Brake Fluid,* 124 *Accelerator Control Systems,* 201 *Occupant Protection in Interior Impact,* 202 *Head Restraints,* 203 *Impact Protection for the Driver From the Steering Control System,* 204 *Steering Control Rearward Displacement,* 205 *Glazing Materials,* 206 *Door Locks and Door Retention Components,* 207 *Seating Systems,* 209 *Seat Belt Assemblies,* 210 *Seat Belt Assembly Anchorages,* 211 *Wheel Nuts, Wheel Discs and Hubcaps,* 212 *Windshield Retention,* 216 *Roof Crush Resistance,* 219 *Windshield Zone Intrusion,* and 302 *Flammability of Interior Materials.*

Additionally, the petitioner states that the non-U.S. certified 1992 Jeep Cherokee complies with the Bumper Standard found in 49 CFR Part 581.

Petitioner also contends that the vehicle is capable of being readily altered to meet the following standards, in the manner indicated:

Standard No. 101 *Controls and Displays:* (a) substitution of a lens marked ''Brake'' for a lens with a noncomplying symbol on the brake failure indicator lamp; (b) installation of a seat belt warning lamp; (c) recalibration of the speedometer/odometer from kilometers to miles per hour.

Standard No. 108 *Lamps, Reflective Devices and Associated Equipment:* (a) installation of U.S.-model headlamp assemblies; (b) installation of U.S.-model front and rear sidemarker/reflector assemblies; (c) installation of U.S.-model taillamp assemblies.

Standard No. 110 *Tire Selection and Rims:* installation of a tire information placard.

Standard No. 111 *Rearview Mirror:* replacement of the convex passenger side rearview mirror.

Standard No. 114 *Theft Protection:* installation of a warning buzzer microswitch and a warning buzzer in the steering lock assembly.

Standard No. 115 *Vehicle Identification Number:* installation of a VIN plate that can be read from outside the left windshield pillar, and a VIN reference label on the edge of the door or latch post nearest the driver.

Standard No. *118 Power Window Systems:* rewiring of the power window system so that the window transport is inoperative when the ignition is switched off.

Standard No. 208 *Occupant Crash Protection:* (a) installation of a U.S.-model seat belt in the driver's position, or a belt webbing actuated microswitch inside the driver's seat belt retractor; (b) installation of an ignition switch actuated seat belt warning lamp and buzzer. The petitioner states that the vehicle is equipped with a lap and shoulder restraint that adjusts by means of an automatic retractor and releases by means of a single push button at each front designated seating position, and with a lap and shoulder restraint that releases by means of a single push button at each rear outboard seating positions.

Standard No. 301 *Fuel System Integrity:* installation of a rollover valve in the fuel tank vent line between the fuel tank and the evaporative emissions collection canister.

Interested persons are invited to submit comments on the petition described above. Comments should refer to the docket number and be submitted to: Docket Section, National Highway Traffic Safety Administration, Room 5109, 400 Seventh Street, S.W., Washington, DC 20590. It is requested but not required that 10 copies be submitted.

All comments received before the close of business on the closing date indicated above will be considered, and will be available for examination in the docket at the above address both before and after that date. To the extent possible, comments filed after the closing date will also be considered. Notice of final action on the petition will be published in the Federal Register pursuant to the authority indicated below.

Authority: 49 U.S.C. 30141(a)(1)(A) and (b)(1); 49 CFR 593.8; delegations of authority at 49 CFR 1.50 and 501.8.

Issued on: May 7, 1996.

Marilynne Jacobs,

Director, Office of Vehicle Safety Compliance.

[FR Doc. 96–11785 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–59–P

[Docket No. 96–39; Notice 1]

Notice of Tentative Decision That Certain Nonconforming Vehicles Are Eligible for Importation

AGENCY: National Highway Traffic Safety Administration, DOT.

ACTION: Request for comments on tentative decision that certain nonconforming vehicles are eligible for importation.

SUMMARY: This notice requests comments on a tentative decision by the National Highway Traffic Safety Administration (NHTSA) that certain motor vehicles that are certified as complying with Canadian Motor Vehicle Safety Standard No. 208, *Occupant Restraint Systems,* but do not comply with Federal Motor Vehicle Safety Standard (FMVSS) No. 208, *Occupant Crash Protection,* are nevertheless eligible for importation into the United States because (1) they are substantially similar to vehicles that were originally manufactured for sale in the United States and that were certified by their manufacturers as complying with the safety standards, and (2) they are capable of being readily altered to conform to FMVSS No. 208.

DATES: The closing date for comments on this tentative decision is June 10, 1996.

FOR FURTHER INFORMATION CONTACT: George Entwistle, Office of Vehicle Safety Compliance, NHTSA (202–366–5306).

SUPPLEMENTARY INFORMATION:

Background

Under 49 U.S.C. § 30141(a)(1)(A) (formerly section 108(c)(3)(A)(i) of the National Traffic and Motor Vehicle Safety Act (15 U.S.C. § 1381 *et seq.*) (the Act)), a motor vehicle that was not originally manufactured to conform to all applicable Federal motor vehicle safety standards (FMVSS) shall be refused admission into the United States unless NHTSA has decided, either pursuant to a petition from the manufacturer or registered importer or on its own initiative, that the motor vehicle is substantially similar to a motor vehicle originally manufactured for importation into and sale in the United States, certified under 49 U.S.C. § 30115 (formerly section 114 of the Act), and of the same model year as the model of the motor vehicle to be compared, and is capable of being readily altered to conform to all applicable Federal motor vehicle safety standards.

On August 13, 1990, NHTSA published a Federal Register notice at 55 FR 32988 announcing that it had made a final determination on its own initiative that certain motor vehicles that are certified by their original manufacturer as complying with all applicable Canadian motor vehicle safety standards (CMVSS) are eligible for importation into the United States under the precursor to 49 U.S.C. § 30141(a)(1)(A). As identified in the notice, the Canadian-certified vehicles determined to be eligible for importation include:

All passenger cars manufactured on or after September 1, 1989 which are equipped by their original manufacturer with an automatic restraint system that complies with Federal Motor Vehicle Safety Standard

(FMVSS) No. 208, *Occupant Crash Protection.*

The notice explained that NHTSA had examined the CMVSS and found that, in most essential respects, they are identical to the FMVSS, and that the most significant difference between the two sets of standards concerned occupant protection requirements. NHTSA noted that CMVSS No. 208, *Occupant Restraint Systems,* does not require a passenger car to be equipped with automatic restraints, in contrast to FMVSS No. 208, *Occupant Crash Protection,* which requires automatic restraints in front designated seating positions for all passenger cars manufactured on and after September 1, 1989. Owing to this difference, and the agency's uncertainty that Canadian-certified vehicles could be retrofitted with automatic restraint systems, NHTSA limited its eligibility determination to passenger cars manufactured before September 1, 1989, or those manufactured on or after that date that are equipped by their original manufacturer with an automatic restraint system that complies with FMVSS No. 208.

The notice observed that in the absence of a determination by NHTSA on its own initiative, any manufacturer or registered importer could petition the agency to determine whether a vehicle requiring the installation of an automatic restraint system to comply with FMVSS No. 208 was eligible for importation into the United States. In the ensuing years, NHTSA has received, and granted, a number of petitions from registered importers seeking import eligibility decisions on vehicles requiring the installation or replacement of automatic restraint systems to comply with FMVSS No. 208. These petitions were granted on the basis of information demonstrating that automatic restraints could be installed in the subject vehicles without the need for significant structural modifications that would render those vehicles incapable of being readily altered to conform to the standards, and therefore ineligible for importation under the criteria specified in 49 U.S.C. § 30141(a)(1)(A).

Through its monitoring of vehicle imports, NHTSA has identified the vehicles listed in the annex to this notice as ones that have been recently imported into the United States from Canada that do not meet the requirements of FMVSS No. 208 because they lack an automatic restraint system at both outboard front seating positions. These vehicles are certified by their original manufacturers as complying with all applicable CMVSS. In order to develop a realistic enforcement policy concerning these vehicles, and to determine whether to allow future importations of similar vehicles, NHTSA is soliciting comments through this notice on whether the vehicles listed in the annex are capable of being readily altered to comply with FMVSS No. 208.

Tentative Decisions

Pending its review of any comments submitted in response to this notice, NHTSA hereby tentatively decides that each of the passenger cars listed in the annex to this notice is substantially similar to a passenger car originally manufactured for sale in the United States, certified under 49 U.S.C. § 30115, and of the same model year, and is capable of being readily altered to conform to all applicable Federal motor vehicle safety standards.

Vehicle Eligibility Number

The importer of a vehicle admissible under any final decision must indicate on the form HS–7 accompanying entry the appropriate vehicle eligibility number indicating that the vehicle is eligible for entry. If these tentative decisions are ultimately made final, all passenger cars listed in the annex to this notice will be eligible for entry into the United States under Vehicle Eligibility No. VSA–1.

Comments

Section 30141(b) of Title 49, U.S. Code requires NHTSA to provide a minimum period for public notice and comment on decisions made on its own initiative consistent with ensuring expeditious, but full consideration and avoiding delay by any person. NHTSA believes that a minimum comment period of 30 days is appropriate for this purpose. Interested persons are invited to submit comments on the tentative decisions described above. It is requested, but not required, that five copies be submitted.

All comments received before the close of business on the closing date indicated above will be considered, and will be available for examination in the docket at the above address both before and after that date. To the extent possible, comments filed after the closing date will also be considered. Notice of NHTSA's final decision will be published in the Federal Register pursuant to the authority indicated below.

Authority: 49 U.S.C. 30141(a)(1)(A) and (b)(1); 49 CFR 593.8; delegation of authority at 49 CFR 1.50.

Issued on: May 7, 1996.

Ricardo Martinez,

Administrator.

Annex

Vehicles Covered by Tentative Decision

The following passenger cars, certified by their original manufacturer as complying with all applicable Canadian Motor Vehicle Safety Standards:

1994 and 1995 Chrysler LeBaron
1994 and 1995 Dodge Spirit
1994 and 1995 Dodge Shadow
1994 and 1995 Dodge Viper
1994 and 1995 Plymouth Acclaim
1994 and 1995 Plymouth Sundance
1995 Mazda Protégé

[FR Doc. 96–11786 Filed 5–9–96; 8:45 am]

BILLING CODE 4910–59–P

Surface Transportation Board [1]

[STB Finance Docket No. 32879]

Nebraska Central Railroad Company—Lease and Operation Exemption—Lines of Union Pacific Railroad Company

AGENCY: Surface Transportation Board, DOT.

ACTION: Notice of Exemption.

SUMMARY: The Board, under 49 U.S.C. 10502, exempts from the prior approval requirements of 49 U.S.C. 10902 the lease and operation by Nebraska Central Railroad Company of three branch lines of Union Pacific Railroad Company consisting of: (1) a line of railroad extending from milepost 83.3 to milepost 80.0 (approximately 3.3 miles); (2) a line of railroad extending from milepost 46.1 to milepost 43.44 (approximately 2.7 miles); and (3) the Norfolk Branch extending from milepost 0.0 to milepost 46.1 (approximately 1.5 miles),[2] in Norfolk, NE.

DATES: This exemption is effective on May 10, 1996. Petitions to stay must be filed by May 16, 1996. Petitions to reopen must be filed by June 3, 1996.

ADDRESSES: Send pleadings, referring to STB Finance Docket No. 32879, to: (1) Surface Transportation Board, Office of the Secretary, Case Control Branch,

[1] The ICC Termination Act of 1995, Pub. L. No. 104–88, 109 Stat. 803, which was enacted on December 29, 1995, and took effect on January 1, 1996, abolished the Interstate Commerce Commission and transferred certain functions to the Surface Transportation Board (Board). This notice relates to functions that are subject to Board jurisdiction pursuant to 49 U.S.C. 10902.

[2] The mileposts here describe locations on separate branch lines. Thus, the mileage between these two points is actually about 1.5 miles, and not 46.1 miles.

1201 Constitution Avenue, N.W., Washington, DC 20423; and (2) Robert A. Wimbish, Suite 420, 1920 N Street, N.W., Washington, DC 20036.

FOR FURTHER INFORMATION CONTACT: Beryl Gordon, (202) 927–7513. [TDD for the hearing impaired: (202) 927–5721.]

SUPPLEMENTARY INFORMATION: Additional information is contained in the Board's decision. To purchase a copy of the full decision, write to, call, or pick up in person from: DC News & Data, Inc., Room 2229, 1201 Constitution Avenue, N.W., Washington, DC 20423. Telephone: (202) 289–4357/4359. [Assistance for the hearing impaired is available through TDD services (202) 927–5721.]

Decided: April 22, 1996.

By the Board, Chairman Morgan, Vice Chairman Simmons, and Commissioner Owen.

Vernon A. Williams,

Secretary.

[FR Doc. 96–11741 Filed 5–9–96; 8:45 am]

BILLING CODE 4915–00–P

DEPARTMENT OF THE TREASURY

[Treasury Directive Number 12–70]

Delegation of Authority of Functions and Establishment of Responsibilities Relating to the Institute of American Indian Arts

May 3, 1996.

1. *Purpose.* This Directive delegates authority and establishes responsibilities for functions relating to the Institute of American Indian and Alaska Native Culture and Arts Development's (referred to as the ''Institute of American Indian Arts'' or the ''Institute'') two trust funds: the Program Enhancement Endowment and the Capital Improvement Endowment.

2. *Scope.* This Directive applies to the Office of the Assistant Secretary for Management & CFO, Office of Inspector General (OIG), Office of the Commissioner of Internal Revenue (IRS), Office of the Commissioner, Financial Management Service (FMS), and Office of the Deputy CFO.

3. *Background.* Treasury Order (TO) 102–11 delegates the authority vested in the Secretary of the Treasury by 20 U.S.C. 4425 for the Institute of American Indian and Alaska Native Culture and Arts Development to the Assistant Secretary for Management & CFO and to the Inspector General.

a. The Institute, a Government-controlled corporation and not an agency of the United States, was established by Congress in October 1986 by Public Law (Pub. L.) 99–498. It submits an annual report to Congress, submits its budget directly to Congress, and receives appropriations (20 U.S.C. 4451) to meet normal operating expenses. It is designated as its own certifying agency for funds appropriated to it (20 U.S.C. 4451)(a)(4)). Pub. L. 101–644, 104 Stat. 4669, dated November 29, 1990, enacted an amended 20 U.S.C. 4425, ''Endowment Programs,'' expanding the role of the Secretary of the Treasury in the Institute. This amendment established the Program Enhancement Endowment and the Capital Improvement Endowment trust funds. Statutory amendments (Pub. L. 101–644, Title V, § 505, dated November 29, 1990) and 20 U.S.C. 4416(f) further established a Federal matching contribution for private contributions to the trust funds, such that the Program Enhancement Endowment and the Capital Improvement Endowment may accept, in addition to cash contributions, ''noncash, in-kind contributions of real or personal property'' which may be converted to cash. Federal matching contributions are limited by the annual appropriation for matching purposes.

b. The statute requires the Secretary of the Treasury to:

(1) establish procedures for appraisal of noncash donations to the Institute;

(2) transfer to the Institute funds constituting the Federal capital contribution to the Program Enhancement and Capital Endowment trust funds established by § 4425(a) and § 4416(f) equal to the amount the Institute demonstrates it has received as private contributions (either cash or noncash). It is Treasury's responsibility to establish appropriate procedures concerning cash contributions and how the Institute will ''demonstrate'' receipt; and

(3) review and approve the governing provisions of the trust funds established under § 4425, including the recordkeeping requirements, as will allow for the Secretary of the Treasury to audit and monitor the activities of the trust funds covered in 20 U.S.C. 4425(c)(3).

4. *Delegations.* The authority delegated to the Assistant Secretary for Management & CFO by TO 102–11 is redelegated as follows.

a. *The Deputy CFO* is delegated the authority contained in 20 U.S.C. 4425 to perform the functions vested in the Secretary by that section, as redelegated under TO 102–11, subject to the delegations in paragraphs 4.b. and 4.c.

b. *The Commissioner of Internal Revenue* is delegated the authority to:

(1) amend the procedures for appraising contributions to the Institute established in accordance with 20 U.S.C. 4425(a)(3); and

(2) assist the General Services Administration (GSA) in reviewing such appraisals.

c. *The Commissioner, Financial Management Service,* is delegated the authority to:

(1) establish and maintain necessary Government account symbols for the Institute's appropriated amounts;

(2) make payment transfers of Federal funds to the Institute pursuant to, and in accordance with, the provisions of 20 U.S.C. 4451, 4425(a)(4) and (b)(5); and

(3) complete all necessary Federal transfer and reporting forms related to the Institute's appropriated amounts.

5. *Responsibilities.*

a. *The Inspector General (IG)* shall perform an annual financial statement audit of the Program Enhancement Endowment and the Capital Improvement Endowment trust funds. The IG shall conduct these audits in-house or through a contractual arrangement.

b. *The Deputy CFO* shall:

(1) review and ensure that the recordkeeping procedures for the trust funds, the Program Enhancement Endowment and the Capital Improvement Endowment, are adequate to protect the financial interest of the United States for the:

(a) investment of Federal funds received by the trust funds; and

(b) expenditure of accumulated interest for the trust funds; and

(2) monitor the activities of the trust funds by reviewing the quarterly unaudited financial statements for the trust funds.

c. *The Commissioner of Internal Revenue* shall perform the duties stated in paragraph 4.b. and as specified in the Memorandum of Understanding (MOU) dated February 3, 1995, between GSA, the Institute and the Department of the Treasury.

d. *The Commissioner, Financial Management Service,* shall perform the duties stated in paragraph 4.c. and as specified in the MOU dated February 3, 1995, between GSA, the Institute and the Department of the Treasury.

6. *Authorities.*

a. TO 102–11, ''Delegation—Institute of American Indian Arts,'' dated March 17, 1992.

b. 20 U.S.C. 4425, ''Endowment Programs.''

c. 20 U.S.C. 4451, ''Authorization of Appropriations.''

d. 20 U.S.C. 4416(f), ''Applicability''

7. *Cancellation.* Treasury Directive 12–70, ''Delegation of Authority of

Functions and Establishment of Responsibilities Relating to the Institute of American Indian Arts,'' dated November 25, 1992, is superseded.

8. *Expiration Date.* This Directive expires three years from the date of issuance unless superseded or cancelled prior to that date.

9. *Office of Primary Interest.* Office of the Deputy CFO, Office of the Assistant Secretary for Management & CFO.

George Muñoz,

Assistant Secretary for Management & CFO.

[FR Doc. 96–11672 Filed 5–9–96; 8:45 am]

BILLING CODE 4810–25–P

[Treasury Order Number 102–17]

Delegation of Authority Concerning the Personnel Security Program

May 2, 1996.

By virtue of the authority vested in the Secretary of the Treasury, including the authority vested by 31 U.S.C. 321(d), it is ordered that:

1. The Department shall maintain a personnel security program to fulfill the responsibilities imposed by 5 U.S.C. 7531–7533; Executive Order (E.O.) 12968, ''Access to Classified Information,'' dated August 2, 1995; E.O. 10450, ''Security Requirements for Government Employees,'' dated April 27, 1953, as amended; and any other applicable authorities. The program shall be applicable throughout the Department.

2. The Assistant Secretary for Management & CFO is delegated the authority of the Secretary to exercise and perform all duties, rights, powers, and obligations under the above-referenced authorities. This delegation includes making all determinations and appointments and issuing any regulations required to implement the Department's personnel security program, except for any matter in which, by law, executive order, or regulation of outside agencies, the personal decision of the head of the agency or principal deputy is required.

3. The Assistant Secretary for Management & CFO is designated pursuant to Section 6.1 of E.O. 12968 as the Senior Agency Official to direct and administer the Department's personnel security program.

4. The responsibilities of the Special Assistant to the Secretary (National Security) continue uninterrupted and are not affected by this Order.

5. The authority delegated by this Order may be redelegated.

Robert E. Rubin,

Secretary of the Treasury.

[FR Doc. 96–11673 Filed 5–9–96; 8:45 am]

BILLING CODE 4810–25–P

Customs Service

Announcement of National Customs Automation Program Test Regarding Reconciliation

AGENCY: U.S. Customs Service, Department of the Treasury.

ACTION: General notice.

SUMMARY: This notice announces Customs plan to conduct a voluntary prototype test regarding reconciliation. This reconciliation test will cover entries to which antidumping and countervailing duties apply. This notice invites public comments concerning any aspect of the planned test, informs interested members of the public of the eligibility requirements for voluntary participation in the testing of this prototype, and describes the basis on which Customs will select participants.

EFFECTIVE DATES: The test of this prototype will commence no earlier than July 9, 1996. This test will end when liquidation or reliquidation of all Reconciliations has become final. Comments concerning the methodology of this prototype must be received on or before June 10, 1996. To participate in this prototype test, the necessary information, as outlined in this notice, must be filed with Customs on or before June 10, 1996.

ADDRESSES: Written comments regarding this notice, and information submitted to be considered for voluntary participation in this prototype should be addressed to Reconciliation Prototype Team, U.S. Customs Service, 1301 Constitution Avenue, N.W., Room 1322, Washington, D.C. 20229–0001.

FOR FURTHER INFORMATION CONTACT: For questions on reconciliation: Rychelle Ingram (202) 927–1131.

For questions on Antidumping and Countervailing duties: Frank Crowe (202) 927–0402.

SUPPLEMENTARY INFORMATION:

Background

Title VI of the North American Free Trade Agreement Implementation Act (the Act), Public Law 103–182, 107 Stat. 2057 (December 8, 1993), contains provisions pertaining to Customs Modernization (107 Stat. 2170). Subtitle B of Title VI establishes the National Customs Automation Program (NCAP)—an automated and electronic system for the processing of commercial importations. Section 637 of the Act amends Section 484 of the Tariff Act of 1930 by establishing a new subsection (b) entitled ''Reconciliation.'' Reconciliation is a planned component of the NCAP. Section 631 authorizes tests of planned NCAP components. Section 101.9(b) of the Customs Regulations (19 CFR 101.9(b)), implements the testing of NCAP components. See T.D. 95–21 (60 FR 14211, March 16, 1995). This test is established pursuant to those regulations.

Previous NCAP initiatives include Customs prototype of remote location filing (60 FR 17605), and the announcement of a reconciliation prototype for related party importers making upward adjustments to the price of imported merchandise, pursuant to 26 U.S.C. 482. (60 FR 46141 and 60 FR 64470.)

I. Description of Proposed Test

The Concept of Reconciliation

Reconciliation will allow an importer to provide Customs with information (other than that related to the admissibility of merchandise), which is not available at the time of entry summary filing, at a subsequent time. A notice of intention to file a Reconciliation (''Notice of Intent'') permits the liquidation of an entry as to all issues other than those which are transferred to the Reconciliation. By filing a Notice of Intent, an importer is requesting that a certain issue be separated from the entry. The importer voluntarily requests and accepts that the issue identified in the Notice of Intent remains open and outstanding and is transferred to the Reconciliation. In this prototype, the issue of liability for antidumping and countervailing duties (AD/CVD) will be transferred to the Reconciliation. This permits Customs to liquidate the underlying entry as to the other issues, e.g., classification, but the issue of liability for AD/CVD is held open at the request of the importer, and is transferred to the Reconciliation.

Upon liquidation of the entry, any decision by Customs entering into that liquidation, e.g., classification, may be protested pursuant to 19 U.S.C. 1514. When the outstanding information, e.g., final antidumping duty owed as per the assessed rate, is later furnished in the Reconciliation, the Reconciliation may be liquidated. The Reconciliation will operate as an entry for purposes of liquidation and protest of the issue in the Reconciliation. The liquidation of the Reconciliation may be protested but

the protest may only pertain to elements contained in the liquidated Reconciliation, i.e., the protest may not re-visit elements previously liquidated in the entry.

The Reconciliation shall be filed within 90 days of posting of liquidation instructions by the Customs Service. Customs posting of the liquidation instructions will serve as the notice to the importer by the Customs Service that a period of review for antidumping or countervailing duty purposes has been completed. Consequently, because the Reconciliation is filed after the suspension of liquidation has been lifted, the liquidation of the Reconciliation is subject to 19 U.S.C. 1504(a), but not subject to 19 U.S.C. 1504(d).

Description of the Reconciliation Prototype

This prototype will commence no sooner than July 9, 1996. Customs would like to afford the opportunity to participate to all those who volunteer for this test. However, the number of participants may be limited in view of the fact that this prototype will be conducted with minimal computer changes, requiring Customs to manually intervene in tracking and processing. While all interested parties are encouraged to apply for participation, Customs, in conjunction with the Department of Commerce (DOC), will specifically be targeting those AD/CVD cases for which liquidation instructions will be issued in the short term. All procedures and processes will be closely coordinated with the selected and affected parties. The purpose of this prototype is to test such operational issues as establishment of the Notice of Intent, liquidation of the underlying entry summaries, and processing and liquidation of the Reconciliation.

This prototype will cover entries to which antidumping and countervailing duties apply. As required by Section 637 of the Act, Customs has coordinated with the DOC in the development of this test, and will continue to consult with the DOC throughout the test.

There are several reasons Customs has selected AD/CVD for this reconciliation prototype. First, this test can be initiated prior to having full computer mainframe programming, partially due to the fact that drawback cannot be claimed on AD/CVD duties. In addition, Customs will no longer have to suspend liquidation as to all issues affecting the entry until final instructions have been issued for all AD/CVD cases on the entry. Faster processing of refunds will result in a cash-flow benefit to importers. Should the AD/CVD assessment result in an increase due Customs, faster processing will enable the government to collect duties more timely. As intended by the Act, liquidation of the non-reconciliation issues on the subject entries will result in a reduction of contingent liabilities for the importer. Finally, this prototype will result in a workload savings for the government. Of all entries currently being withheld from liquidation, 75% are suspended for pending AD/CVD cases. Reconciliation provides Customs with the authority to liquidate the underlying entries as to all issues other than the liability for the AD/CVD case, which is identified by the importer in the Notice of Intent, and at his request, transferred to the Reconciliation. By submitting a Notice of Intent, an importer is requesting that the issue of liability for AD/CVD remain open and be transferred to the Reconciliation.

There are various situations which lend themselves to this prototype, including (1) entries having one AD/CVD case, for which the importer wants to reduce its contingent liabilities and leave only the AD/CVD case open on the Reconciliation, and (2) entries having multiple AD/CVD cases, one or more of which has been terminated, or one or more of which has had liquidation instructions issued. Also, parties who have drawback claims against import entries that are suspended for AD/CVD will expedite the liquidation of their drawback entries if they use this prototype to transfer the AD/CVD issue off the import entries.

The following is an example of a situation which would benefit from this prototype. Importer X has 800 entries filed in the port of Cleveland, all of which have merchandise which is subject to three antidumping cases. The DOC has previously provided Customs with liquidation instructions on two of the cases, each having an assessed rate lower than the deposit rate. As a result, Customs owes importer X refunds based on the results of the two cases. However, the 800 entries presently must continue to be suspended from liquidation, pending instructions on the third case. No money is refunded until the entries can be liquidated. In the case of a separate Notice of Intent being filed for each of the three cases, Customs is capable of isolating each case on a single Reconciliation and liquidating the underlying entries as to the other issues. As the DOC provides instructions, each case can be liquidated individually. In this example, this prototype provides for more efficient processing by Customs and quicker refunds to the importer. Additionally, Customs would issue one check for each Reconciliation, as opposed to the current obligation of issuing 800 separate checks.

Customs posting of the AD/CVD liquidation instructions on the Customs Electronic Bulletin Board and the Administrative Message System will initiate the 90 days in which the participant has to file the Reconciliation. Customs posting of the liquidation instructions will serve as the notice to the importer by the Customs Service that a period of review for antidumping or countervailing duty purposes has been completed. The publication in the Federal Register by the International Trade Administration (DOC) does not constitute Commerce's instructions to Customs to liquidate, and as such, will NOT trigger the 90 day period for submission of the Reconciliation.

Prerequisites for Reconciliation Under this Prototype

The following are the prerequisites for this prototype covering AD/CVD transactions:

A. *Common Elements:* Each Reconciliation under this prototype will be limited to entries filed by one importer and one filer, and in one port location. Importers who file entries at more than one port may participate if the other prerequisites are met; however, they will have to file one Notice of Intent/Reconciliation for each port. Each Reconciliation is limited to one Antidumping or Countervailing duty case (the individual ten digit case number), and will cover only one manufacturer/shipper/grower. Each Reconciliation will cover only one review period, as defined in 19 CFR 353.22 and 19 CFR 355.22.

B. *Bonding:* Adequate bonding will be required for each Reconciliation. Since there is no additional liability created on the Reconciliation, the bond filed on the underlying entries will in most cases be used to cover the Reconciliation. However, Customs will analyze each participant's individual situation, and take action to ensure sufficient bond coverage exists. While Customs prefers to have one common set of legally responsible parties for each Reconciliation, importers with entries filed within one review period which were secured by more than one surety will not be excluded from participation in this prototype.

C. *Eligible Entries:* The following types of entries will be eligible for this prototype: (1) Entry type 03—Antidumping and Countervailing duty consumption entries, (2) Entry type 06—Foreign trade zone consumption entries, and (3) Entry type 07—Quota/Visa and

Antidumping/Countervailing duty consumption entries.

Customs is developing a system to accommodate the details involved on Reconciliations covering warehouse withdrawals. Importers interested in filing a Reconciliation on warehouse withdrawals (Entry type 34—Antidumping/Countervailing duty warehouse withdrawal, and Entry type 38—Quota/Visa and Antidumping/Countervailing duty warehouse withdrawal) are encouraged to submit comments and apply for participation, if interested.

D. *Time frame:* Those entries filed via ABI between *February 1, 1990* and the start of this test will be considered eligible for this prototype. (Entries filed prior to February 1, 1990 are not eligible for this test because prior to such date, Customs did not track AD/CVD case information by entry summary line within the Automated Commercial System.)

E. *Notice of Intent/Reconciliation:* Once a participant is selected, a Notice of Intent must be filed. The Notice of Intent is irrevocable. The Notice of Intent must contain the Reconciliation number and the common elements of the Reconciliation, (i.e., importer/filer/AD–CVD case/review period/manufacturer/Port).

The Reconciliation will be due within 90 days of Customs' posting of the liquidation instructions. For AD/CVD cases which have had liquidation instructions previously posted by Customs, the filing of the Notice of Intent will trigger the 90 days for submission of the Reconciliation. For purposes of this prototype, the Reconciliation will be submitted to Customs in an ASCII text, tab-delimited file format, both on hard copy and diskette, and will contain the following information *for each entry line subject to the Reconciliation:*

(1) Entry number;

(2) Date of entry;

(3) Date of export from foreign country (if Reconciliation pertains to CVD case);

(4) Entered value;

(5) AD/CVD duty deposited (Indicate ''B'' if bonded);

(6) Amount of supplemental AD/CVD duty payment(s), if any;

(7) Date(s) of supplemental payment(s), if any;

(8) Total quantity (only if liquidation instructions provide specific rate of duty);

(9) AD/CVD duty due as per assessed rate; and

(10) Net difference in duty.

Participants will be provided with a sample Reconciliation.

F. *Liquidation:* Importers who chose to participate in this prototype will recognize that the liquidation of the underlying entries pertains only to those issues not identified by the importer on the Notice of Intent. Upon liquidation of the underlying entries, any decisions of the Customs Service entering into that liquidation can be protested pursuant to 19 U.S.C. 1514. The liquidation of the Reconciliation will be posted to the Bulletin Notice of Liquidation. The liquidation of the Reconciliation may also be protested, but the protest may only pertain to elements contained in the liquidated Reconciliation, i.e. the protest may not re-visit elements previously liquidated in the entry.

Under this prototype, once the participant files the Notice of Intent, the referenced entries will be liquidated as to all issues other than that identified in the Notice of Intent, barring any outstanding non-reconciliation issue. The AD/CVD liability issue is transferred to the Reconciliation. The liquidation of tariff classification/rate of duty and/or the appraised value under 19 U.S.C. 1401a shall not preclude the assessment on the Reconciliation of AD/CVD duties according to the instructions issued by the DOC to Customs.

Regulatory Provisions Suspended

Section 113.62 of the Customs Regulations (19 CFR 113.62), pertaining to basic importation and entry bond conditions, will be suspended during this prototype test. Certain provisions in Part 159 of the Customs Regulations (19 CFR Part 159), pertaining to liquidation of duties, will also be suspended during this prototype test.

II. Eligibility Criteria

The following requirements must be met to be considered for selection in this prototype:

(1) All entries and entry summaries subject to the Reconciliation must have been filed via ABI on or after February 1, 1990 and before the start of this test.

(2) There can be no more than 1,000 entries subject to a single Reconciliation.

(3) Adequate bond coverage must exist for the Reconciliation.

(4) Participants may not be the subject of a current audit or investigation by the Customs Service. Closed audits/investigations will not necessarily preclude an importer from participating. However, the findings will be taken into consideration, as will the importer's demonstrated efforts to correct past problems.

(5) Participants must be willing and able to supply the information identified above in the Reconciliation in the specified text, tab-delimited file format.

(6) Participants must agree to participate in the evaluation of this test.

Note that participation in this test will not constitute confidential information and that lists of participants will be made available on the Customs Electronic Bulletin Board and the Administrative Message System.

Reconciliation Prototype Application

This notice requests importers, or brokers or attorneys on behalf of importers, to voluntarily apply for participation in this prototype by submitting to the Reconciliation Prototype Team, U.S. Customs Service, 1301 Constitution Avenue, N.W., Room 1322, Washington, D.C. 20229–0001, on or before the date set forth in the effective date paragraph at the beginning of this notice, the following information:

(1) Importer name and IR number;

(2) Broker name and filer code;

(3) Surety name(s) and surety code(s);

(4) Bond coverage, i.e., whether a continuous bond and/or single entry bonds were used for coverage on the subject entries;

(5) Supplier name, address, and manufacturer's number;

(6) AD/CVD case number at the 10 digit level and the review period being reconciled;

(7) Commodities covered under the Reconciliation;

(8) Port(s) at which entries have been filed and at which the Notice(s) of Intent will be filed;

(9) Number of entries covered under the Reconciliation;

(10) Any supplemental payments made on the subject entries;

(11) Main contact person and telephone number for participation questions; and

(12) Any comments on prototype participation.

By applying to participate in this test, the importer is agreeing to participate pursuant to the terms of the test as defined in this notice.

Basis for Participant Selection

Eligible importers or importers with brokers will be considered for selection as participants in this prototype. Selection will be based on electronic capabilities and volume of entries within the designated criteria. In addition, Customs will work with the DOC to identify those cases which lend themselves to this prototype. The amount and timing of supplemental payments made for an AD/CVD case may have impact on participant selection. Customs is looking for a variety of circumstances and

participants in this prototype; however, a limited number of participants will be selected. This prototype will be limited to 25 Reconciliations, due to the minimal automated programming available to support this test. We stress that those applicants not selected for participation, and any interested parties, are invited to comment on the design, conduct, and evaluation of this prototype. Participants selected will be notified in writing. The list of participants will be made available on the Customs Electronic Bulletin Board and the Administrative Message System.

III. Test Evaluation Criteria

Once participants are selected, Customs and the participants will meet to review all public comments received concerning any aspect of the test program or procedures, finalize procedures in light of those comments, form problem-solving teams, and establish baseline measures and evaluation methods and criteria. Interim evaluations of the prototype will be published on the Customs Electronic Bulletin Board, and the results of the final prototype evaluation will be published in the Federal Register as required by 19 CFR 101.9(b). The following evaluation methods and criteria have been suggested:

1. Baseline measurements to be established through dataqueries and questionnaires;
2. Reports to be run through use of dataquery throughout the prototype; and
3. Questionnaires from both trade and Customs participants to be used before, during, and after the prototype period.

Preliminary suggestions for evaluation criteria are workload impact (workload shifts, cycle time, etc.), cost savings (staff, interest, issuance of fewer checks or bills, tracking refunds or bills, reduction in contingent liabilities, etc.), policy and procedural accommodation, trade compliance impact, problem solving and system efficiency.

Customs will request that test participants be active in the evaluation, identifying costs and savings experienced in this prototype.

Customs intends to conduct several prototypes of the reconciliation component of the NCAP. These tests will determine the system and operational design of reconciliation which will allow all filers to participate in this type of entry process at a national level. At this time, how the final reconciliation program will operate is unknown. Prototype participants must recognize that these are true prototypes to test the benefits and potential problems of reconciliation for Customs, the trade community, and other parties impacted by this program. It is important to note that time and money spent on these prototypes may not carry forward to the final program.

The next reconciliation prototype is tentatively scheduled to commence no sooner than January, 1997. This subsequent prototype will continue to address operational impact and procedures, and begin addressing additional systemic needs. This prototype is intended to include AD/CVD, as well as other issues which lend themselves to processing by reconciliation. The experience gained from the reconciliation prototype for AD/CVD transactions will be incorporated into subsequent prototypes.

Dated: May 6, 1996.

Samuel H. Banks,

Assistant Commissioner, Office of Field Operations.

[FR Doc. 96–11734 Filed 5–9–96; 8:45 am]

BILLING CODE 4820–02–P

[T.D. 96–38]

Tuna Fish—Tariff-Rate Quota

AGENCY: U.S. Customs Service, Department of the Treasury.

ACTION: Announcement of the quota quantity for tuna for Calendar Year 1996.

SUMMARY: This document sets forth the tariff-rate quota for the Calendar Year 1996, on tuna classifiable under item 1604.14.20, Harmonized Tariff Schedule of the United States.

EFFECTIVE DATES: The 1996 tariff-rate quota is applicable to tuna fish entered, or withdrawn from warehouse, for consumption during the period January 1 through December 31, 1996.

FOR FURTHER INFORMATION CONTACT: Karen L. Cooper, Chief, Quota Branch, Technical Programs Division, Trade Compliance Team, Office of Field Operations, U.S. Customs Service, Washington, D.C. 20229, (202) 927–5401.

Background

Each year the tariff-rate quota for tuna fish described in item 1604.14.20, Harmonized Tariff Schedule of the United States (HTSUS), is based on the United States canned tuna production for the preceding calendar year. This document sets forth the tariff-rate quota for the Calendar Year 1996. It has now been determined that 36,300,379 kilograms of tuna may be entered for consumption or withdrawn from warehouse for consumption during the Calendar Year 1996, at the rate of 6 percent ad valorem under item 1604.14.20, HTSUS. Any such tuna which is entered, or withdrawn from warehouse, for consumption during the current calendar year in excess of this quota will be dutiable at the rate of 12.5 percent ad valorem under item 1604.14.30 HTSUS. (OFO–TC:T:Q)

Dated: May 6, 1996.

Michael H. Lane,

Acting Commissioner.

[FR Doc. 96–11733 Filed 5–9–96; 8:45 am]

BILLING CODE 4820–02–P

Fiscal Service

[Dept. Circ. 570, 1995 Rev., Supp. No. 12]

Surety Companies Acceptable on Federal Bonds; Capital Reinsurance Company

A Certificate of Authority as an acceptable reinsurer on Federal Bonds is hereby issued to the following company under Sections 9304 to 9308, Title 31, of the United States Code. Federal bond-approving officers should annotate their reference copies of the Treasury Circular 570, 1995 Revision, on page 34450 to reflect this addition:

Capitol Reinsurance Company. BUSINESS ADDRESS: 1325 Avenue of the Americas, New York, NY 10019. PHONE: (212) 974–0100. UNDERWRITING LIMITATION *b*/: $27,928,000. INCORPORATED IN: Maryland.

Certificates of Authority expire on June 30 each year, unless revoked prior to that date. The Certificates are subject to subsequent annual renewal as long as the companies remain qualified (31 CFR, Part 223). A list of qualified companies is published annually as of July 1 in Treasury Department Circular 570, with details as to underwriting limitations.

Copies of the Circular may be obtained by calling the U.S. Department of the Treasury, Financial Management Service, computerized public bulletin board system (FMS Inside Line) at (202) 874–6817/7034/6953/6872 or by purchasing a hard copy from the Government Printing Office (GPO), Washington, DC, telephone (202) 512–0132. When ordering the Circular from GPO, use the following stock number: 048–000–00489–0.

Questions concerning this Notice may be directed to the U.S. Department of the Treasury, Financial Management Service, Funds Management Division, Surety Bond Branch, 3700 East-West Highway, Room 6F04, Hyattsville, MD 20782, telephone (202) 874–6507.

Dated: April 18, 1996.

Charles F. Schwan III,

Director, Funds Management Division, Financial Management Service.

[FR Doc. 96–11751 Filed 5–9–96; 8:45 am]

BILLING CODE 4810–35–M

UNITED STATES ENRICHMENT CORPORATION

Sunshine Act Meeting

AGENCY: United States Enrichment Corporation, Board of Directors.

TIME AND DATE: 8:00 a.m., Tuesday, May 14, 1996.

PLACE: USEC Corporate Headquarters, 6903 Rockledge Drive, Bethesda, Maryland 20817.

STATUS: The meeting will be closed to the public.

MATTERS TO BE CONSIDERED:

- Review of commercial, financial and internal personnel issues of the Corporation.

CONTACT PERSON FOR MORE INFORMATION: Barbara Arnold 301–564–3354.

Dated: May 7, 1996.

William H. Timbers, Jr.,

President and Chief Executive Officer.

[FR Doc. 96–11890 Filed 5–8–96; 12:28 pm]

BILLING CODE 8720–01–M

federal register

Friday
May 10, 1996

Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Parts 35, 37 and 385

Electric Utilities (Federal Power Act); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Final Rules and Proposed Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35 and 385

[Docket Nos. RM95–8–000 and RM94–7–001; Order No. 888]

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

Issued April 24, 1996.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing a Final Rule requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. The Final Rule also permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and Federal Power Act section 211 transmission services. The Commission's goal is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.

EFFECTIVE DATE: This Final Rule will become effective on July 9, 1996.

FOR FURTHER INFORMATION CONTACT:

David D. Withnell (Legal Information—Docket No. RM95–8–000), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 208–2063

Deborah B. Leahy (Legal Information—Docket No. RM94–7–001), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 208–2039

Michael A. Coleman (Technical Information), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 208–1236.

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in the Public Reference Room at 888 First Street, NE., Washington, DC 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing 202–208–1397 if dialing locally, or 1–800–856–3920 if dialing long distance. CIPS is also available through the Fed World system (by modem or Internet). To access CIPS, set your communications software to 19200, 14400, 12000, 9600, 7200, 4800, 2400, or 1200 bps, full duplex, no parity, 8 data bits and 1 stop bit. The full text of this order will be available on CIPS indefinitely in ASCII and WordPerfect 5.1 format. The complete text on diskette in Wordperfect format may also be purchased from the Commission's copy contractor, La Dorn Systems Corporation, also located in the Public Reference Room at 888 First Street NE., Washington, DC 20426.

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Statement of Commissioner Hoecker
Statement of Commissioner Massey

I. Introduction/Summary

Today the Commission issues three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.[1] The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce. A second critical aspect of the rules is to address recovery of the transition costs of moving from a monopoly-regulated regime to one in which all sellers can compete on a fair basis and in which electricity is more competitively priced.

In the year since the proposed rules were issued,[2] the pace of competitive changes in the electric utility industry has accelerated. By March of last year, 38 public utilities had filed wholesale open access transmission tariffs with the Commission. Today, prodded by such competitive changes and encouraged by our proposed rules, 106 of the approximately 166 public utilities that own, control, or operate[3] transmission facilities used in interstate commerce have filed some form of wholesale open access tariff. In addition, since the time the proposed rules were issued, numerous state regulatory commissions have adopted or are actively evaluating retail customer choice programs or other utility restructuring alternatives. These events have been spurred by continuing pressures in the marketplace for changes in the way electricity is bought, sold, and transported. Increasingly, customers are demanding the benefits of competition in the growing electricity commodity market.

The Commission estimates the potential quantitative benefits from the Final Rule will be approximately $3.8 to $5.4 billion per year of cost savings, in addition to the non-quantifiable benefits that include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. The continuing competitive changes in the industry and the prospect of these benefits to customers make it imperative that this Commission take the necessary steps within its jurisdiction to ensure that all wholesale buyers and sellers of electric energy can obtain non-discriminatory transmission access, that the transition to competition is orderly and fair, and that the integrity and reliability of our electricity infrastructure is maintained.

In this Rule, the Commission seeks to remedy both existing and future undue discrimination in the industry and realize the significant customer benefits that will come with open access. Indeed, it is our statutory obligation under sections 205 and 206 of the Federal Power Act (FPA) to remedy undue discrimination.

To do so, we must eliminate the remaining patchwork of closed and open jurisdictional transmission systems and ensure that all these systems, including those that already provide some form of open access, cannot use monopoly power over transmission to unduly discriminate against others. If we do not take this step now, the result will be benefits to some customers at the expense of others. We have learned from our experience in the natural gas area the importance of addressing competitive transition issues early and with as much certainty to market participants as possible.

Accordingly, in this proceeding and in the accompanying proceeding on OASIS, the Commission, pursuant to its authorities under sections 205 and 206 of the FPA:

- Requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce
- To file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service;
- To take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs;
- To develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that the public utility enjoys, and further requires public utilities to separate transmission from generation marketing functions and communications;
- Clarifies Federal/state jurisdiction over transmission in interstate commerce and local distribution and provides for deference to certain state recommendations; and
- Permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and FPA section 211 transmission services.

Open Access

The Final Rule requires public utilities to file a single open access tariff that offers both network, load-based service and point-to-point, contract-based service. The Rule contains a pro forma tariff that reflects modifications to the NOPR's proposed terms and conditions and also permits variations for regional practices. All public utilities subject to the Rule, including those that already have tariffs on file, will be required to make section 206 compliance filings to meet the new pro forma tariff non-price minimum terms and conditions of non-discriminatory transmission. Utilities may propose their own rates in a section 205 compliance filing.

The Rule provides that public utilities may seek a waiver of some or all of the requirements of the Final Rule. In addition, non-public utilities may seek a waiver of the tariff reciprocity provisions.

The Final Rule does not generically abrogate existing requirements contracts, but will permit customers and public utilities to seek modification, or termination, of certain existing requirements contracts on a case-by-case basis. As to coordination arrangements and contracts, the Rule finds that these arrangements and contracts may need to be modified to remove unduly discriminatory transmission access and/or pricing provisions. Such arrangements and agreements include power pool agreements, public utility

[1] These rules are the rules on open access and stranded costs in the above dockets (FERC Stats. & Regs. ¶ 31,036), and an accompanying rule on Open Access Same-Time Information System and Standards of Conduct (OASIS Final Rule) (FERC Stats. & Regs. ¶ 31,037) being issued contemporaneously. The Commission also is issuing contemporaneously a notice of proposed rulemaking on capacity reservation open access transmission tariffs in Docket No. RM96–11–000, FERC Stats. & Regs. ¶ 32,517. These final rules and proposed rule are being published concurrently in the Federal Register.

[2] On March 29, 1995, the Commission issued two notices of proposed rulemaking concerning open access transmission and stranded cost recovery. Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 60 FR 17662 (April 7, 1995), FERC Stats. & Regs. ¶ 32,514 (1995). On December 13, 1995, the Commission issued a notice of proposed rulemaking on information systems. Real-Time Information Networks and Standards of Conduct, Notice of Proposed Rulemaking, 60 FR 66182 (December 21, 1995), FERC Stats. & Regs. ¶ 32,516 (1995).

[3] The Commission's notice of proposed rulemaking in the above dockets proposed to apply the proposed requirements to public utilities that own and/or control facilities used for the transmission of electric energy in interstate commerce. ''Own and/or control'' is intended to include public utilities that ''operate'' facilities used for the transmission of electric energy in interstate commerce. However, we have modified the Final Rule regulatory text to remove any ambiguity.

holding company agreements, and certain bilateral coordination agreements. The Rule provides guidance and timelines for modifying unduly discriminatory coordination arrangements and contracts, and specifies when the members of such arrangements must begin to conduct trade with each other using the same open access tariff offered to others. The Rule also provides guidance regarding the formation of independent system operators (ISOs).

The Rule does not require any form of corporate restructuring, but will accommodate voluntary restructuring that is consistent with the Rule's open access and comparability policies.

As discussed in the NOPR, not all owners or controllers of interstate transmission facilities are subject to the Commission's jurisdiction under sections 205 and 206 of the FPA and therefore are not subject to this Rule's open access requirements. Therefore, the Final Rule retains the proposed reciprocity provision in the pro forma tariff. Without such a provision, non-open access utilities could take advantage of the competitive opportunities of open access, while at the same time offering inferior access, or no access at all, over their own facilities. Thus, open access utilities would be unfairly burdened. We note that some non-jurisdictional utilities have expressed an interest in a mechanism for obtaining a Commission determination that their transmission tariffs satisfy the reciprocity provisions in the pro forma tariffs, and we provide such a mechanism in the Rule.

The Final Rule does not generically provide for market-based generation rates. Although the Rule codifies the Commission's prior decision that there is no generation dominance in new generating capacity, intervenors in cases may raise generation dominance issues related to new capacity. In addition, to obtain market-based rates for existing generation, we will continue to require public utilities to show, on a case-by-case basis, that there is no generation dominance in existing capacity. Further, in all market-based rate cases, we will continue to look at whether an applicant and its affiliates could erect other barriers to entry and whether there may be problems due to affiliate abuse or reciprocal dealing.

Finally, contemporaneously with this Rule the Commission issues an NOPR on capacity reservation tariffs as an alternative, and perhaps superior, means of remedying undue discrimination.

Transmission/Local Distribution

The Rule clarifies the Commission's interpretation of the Federal/state jurisdictional boundaries over transmission and local distribution. While we reaffirm our conclusion that this Commission has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, we nevertheless recognize the very legitimate concerns of state regulatory authorities as they contemplate direct retail access or other state restructuring programs. Accordingly, we specify circumstances under which we will give deference to state recommendations. Although jurisdictional boundaries may shift as a result of restructuring programs in wholesale and retail markets, we do not believe this will change fundamental state regulatory authorities, including authority to regulate the vast majority of generation asset costs, the siting of generation and transmission facilities, and decisions regarding retail service territories. We intend to be respectful of state objectives so long as they do not balkanize interstate transmission of power or conflict with our interstate open access policies.

Stranded Costs

With regard to stranded costs, the Final Rule adopts the Commission's supplemental proposal. It will permit utilities to seek extra-contractual recovery of stranded costs associated with a limited set of existing (executed on or before July 11, 1994) wholesale requirements contracts and provides that the Commission will be the primary forum for utilities to seek recovery of stranded costs associated with retail-turned-wholesale transmission customers. It also will allow utilities to seek recovery of stranded costs caused by retail wheeling only in circumstances in which the state regulatory authority does not have authority to address retail stranded costs at the time the retail wheeling is required. The Rule retains the revenues lost approach for calculating stranded costs and provides a formula for calculating such costs.

Environmental Issues

The Commission has prepared a Final Environmental Impact Statement (FEIS) evaluating the possible environmental consequences of changes in the bulk power marketplace expected to occur as a result of the open access requirements of this Final Rule. The FEIS focuses, as do most commenters, on possible increases in emissions of nitrogen oxides (NO_X) from certain fossil-fuel fired generators, which could affect air quality in the producing region and in areas to which these emissions may be carried.

In response to comments on the Draft EIS, the Commission performed numerous additional studies. The FEIS finds that the relative future competitiveness of coal and natural gas generation is the key variable affecting the impact of the Final Rule. If competitive conditions favor natural gas, the Rule is likely to lead to environmental benefits. Both EPA and the Commission staff believe this projected scenario is the more likely one. If competitive conditions favor coal, the Rule may lead to small negative environmental impacts. However, even using the most extreme, unlikely assumptions about the future of the industry, the negative consequences are not likely to occur until after the turn of the century. Because the impacts will remain modest at least until 2010, there is no need for an interim mitigation program. In addition, even if the data showed more significant negative consequences requiring mitigation, the Commission does not have the statutory authority under the Federal Power Act or the expertise to address this possible far-term problem. The Commission believes, however, that there is time for federal and state air quality authorities to address any potential adverse impact as part of a comprehensive NO_X regulatory program under the Clean Air Act.[4]

Despite our conclusions regarding the lack of environmental impacts expected to result from the Rule, the Commission has examined a wide variety of proposals for mitigating possible adverse effects. We share the view of most commenters that the preferred approach for mitigating increased NO_X emissions generally is a NO_X cap and trading regulatory program comparable to that developed by Congress to address sulfur dioxide emissions in the Clean Air Act Amendments of 1990.[5] The Commission has examined various means of establishing such a program, including use of existing federal authorities under the Clean Air Act, cooperative efforts by state and federal air quality regulators, and development of a new emissions regulatory program administered by the Commission under the Federal Power Act. The Commission has concluded that a NO_X regulatory program could best be developed and administered under the Clean Air Act, in cooperation with interested states, and offers to lend Commission support

[4] 42 U.S.C. 7401, *et seq.*

[5] 42 U.S.C.A. 7651b–e.

to that effort should it become necessary.

Conclusion

The Commission believes that the Final Rule will remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to competitive bulk power markets.

II. Public Reporting Burden

The Open Access Final Rule and the Stranded Cost Final Rule specify filing requirements to be followed by public utilities that own, control or operate transmission facilities in interstate commerce in making non-discriminatory open access tariff filings and filings to recover legitimate, prudent and verifiable stranded costs. The information collection requirements of the final rules are attributable to FERC–516 ''Electric Rate Filings.'' The current total annual reporting burden for FERC–516 is 828,300 hours.

A. Docket No. RM95–8–000 (Open Access Final Rule)

The Open Access Final Rule requires public utilities filing non-discriminatory open access tariffs to provide certain information to the Commission. The Commission estimated that the public reporting burden for the information collection would average 300 hours per response. This estimate included time for reviewing the requirements of the Commission's regulations, searching existing data sources, gathering and maintaining the necessary data, completing and reviewing the collection of information, and filing the revised information. No comments on the burden estimate were received. Because the Final Rule adopts essentially the same information requirements that are contained in the proposed rule, we believe that the average filing burden is same for the Final Rule.

In the proposed rule, the Commission noted that there are approximately 328 public utilities, including marketers and wholesale generation entities. We initially estimated that 137 public utilities own, control or operate facilities used for the transmission of electric energy in interstate commerce, and would be subject to the filing requirements of the proposed rule. Upon further review, the Commission believes that approximately 166 public utilities will respond to the information collection. Accordingly, the public reporting burden is estimated to be 49,800 hours.

B. Docket No. RM94–7–001 (Stranded Cost Final Rule)

In the supplemental notice of proposed rulemaking, the Commission estimated that the information requirements of the proposed rule would not differ substantially from those contained in the initial proposed rule. In that notice, the Commission estimated that the public reporting burden for the information requirements contained in the proposed rule would be 50 hours per response with 10 responses annually. No comments on this filing burden were received. The information requirements adopted in the Stranded Cost Final Rule are not substantially different from those in the proposed rule. Therefore, the Commission concludes that there will be no additional public filing burden associated with the Stranded Cost Final Rule.

III. Background

In the NOPR, we set out a detailed statement of the events leading up to this rulemaking. We repeat that background here, updated to reflect what has happened since March 1995, and discuss why it is necessary to undertake regulatory reform in the electric industry at this time. We do so to provide the necessary backdrop to our action in adopting this Rule.

A. Structure of the Electric Industry at Enactment of Federal Power Act

The Federal Power Act was enacted in an age of mostly self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered limited service areas. This structure of separate systems arose naturally due primarily to the cost and technological limitations on the distance over which electricity could be transmitted.

Through much of the 1960s, utilities were able to avoid price increases, but still achieve increased profits, because of substantial increases in scale economies, technological improvements, and only moderate increases in input prices.[6] Thus, there was no pressure on regulatory commissions to use regulation to affect the structure of the industry.[7]

B. Significant Changes in the Electric Industry

In the late 1960s and throughout the 1970s, a number of significant events occurred in the electric industry that changed the perceptions of utilities and began a shift to a more competitive marketplace for wholesale power.[8] This was the beginning of periods of rapid inflation, higher nominal interest rates, and higher electricity rates.[9] During this time, consumers became concerned about higher electricity rates and questioned any price increases filed by utilities.[10]

During this same time frame, the construction of nuclear and other capital-intensive baseload facilities—actively encouraged by federal and some state governments—contributed to the continuing cost increases and uncertainties in the industry.[11] These investments were made based on the assumptions that there would be steady increases in the demand for electricity and continued large increases in the price of oil.[12] However, due to conservation and economic downturns, the expected demand increases did not materialize. Load growth virtually disappeared in some areas, and many utilities unexpectedly found themselves with excess capacity.[13] In addition, by the 1980s, the oil cartel collapsed, with a resulting glut of low-priced oil.[14] At the same time, inflation substantially increased the costs of these large

[6] Paul L. Joskow, Inflation and Environmental Concern: Structural Change in the Process of Public Utility Regulation, 17 J. Law & Econ. 291, 312 (1974); *see also* Charles F. Phillips, Jr., *The Regulation of Public Utilities* 11 (1988).

[7] *See* Joskow, *supra* at 312; *see also* Phillips, *supra* at 12.

[8] *See* Joskow, *supra* at 312; *see also* Phillips, *supra* at 12–13.

[9] *See* Joskow, *supra* at 312–13; *see also* Phillips, *supra* at 13. The Arab oil embargo resulted in significantly higher oil prices through the 1970s. *See* Richard J. Pierce, Jr., The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity, 132 U. Pa. L. Rev. 497, 501 (1984).

[10] *See* Joskow, *supra* at 313; *see also* Phillips, *supra* at 13.

[11] *See generally* Jersey Central Power & Light Company v. FERC, 810 F.2d 1168, 1171 (D.C. Cir. 1987).

[12] *Id.*

[13] *See* Pierce, *supra* at 503. By 1983, the Department of Energy had estimated that the sunk costs for canceled nuclear plants alone amounted to $10 billion. *Id.* at 498.

[14] *Id.*

baseload generating plants.[15] Surging interest rates further increased the cost of the capital needed to finance and capitalize these projects and completion schedules were significantly extended by, in part, more stringent safety and environmental requirements.[16]

As a result, expensive large baseload plants for which there was little or no demand, came onto the market or were in the process of being constructed. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25% after adjusting for general inflation.[17] Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86% after adjusting for inflation.[18] The rapidly increasing rates for electric power during this period, together with the opportunities provided by the Public Utility Regulatory Policies Act of 1978 (PURPA) (discussed *infra*), also prompted some industrial customers to bypass utilities by constructing their own generation facilities. This further exacerbated rate increases for remaining customers—primarily residential and commercial customers.

Consumers responded to these ''rate shocks'' by exerting pressure on regulatory bodies to investigate the prudence of management decisions to build generating plants, especially when construction resulted in cost overruns, excess capacity, or both. Between 1985 and 1992, writeoffs of nuclear power plants totalled $22.4 billion.[19] These writeoffs significantly reduced the earnings of the affected utilities.[20] Delays in obtaining rate increases to reflect the effects of inflation further reduced investor returns. Thus, many utilities became reluctant to commit capital to long-term construction decisions involving large scale generating plants.[21]

In addition to economic changes in the industry, significant technological changes in both generation and transmission have occurred since 1935. Through the 1960s, bigger was cheaper in the generation sector and the industry was able to capitalize on economies of scale to produce power at lower per-unit costs from larger and larger plants.[22] As a result, large utility companies that could finance and manage construction projects of larger scale had a price advantage over smaller utility companies and customers who might otherwise have considered building their own generating units. Scale economies encouraged power generation by large vertically-integrated utility companies that also transmitted and distributed power. Beginning in the 1970s, however, additional economies of scale in generation were no longer being achieved.[23] A significant factor was that larger generation units were found to need relatively greater maintenance and experience longer downtimes.[24] The electric industry faced the situation ''where the price of each incremental unit of electric power exceeded the average cost.''[25] Bigger was no longer better.

Further dictating against larger generation units were advances in technologies that allowed scale economies to be exploited by smaller size units, thereby allowing smaller new plants to be brought on line at costs below those of the large plants of the 1970s and earlier. Such new technologies include combined cycle units and conventional steam units that use circulating fluidized bed boilers.[26]

The combined cycle generating plants generally use natural gas as their primary fuel. This technology has been made possible by the development of more efficient gas turbines, shorter construction lead times, lower capital costs, increased reliability, and relatively minimal environmental impacts.[27] Similarly, the circulating fluidized bed combustion boilers, fueled by coal and other conventional fuels, provide a more efficient and less polluting resource.

Today, ''the optimum size (of generation plants) has shifted from (more than 500 MW) (10-year lead time) to smaller units (one-year lead time) (in the 50- to 150–MW range).''[28] Indeed, smaller and more efficient gas-fired combined-cycle generation facilities can produce power on the grid at a cost ranging from 5 cents per kWh to less than 3 cents per kWh.[29] This is significantly less than the costs for large plants constructed and installed by utilities over the last decade, which were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.[30] Significant changes have also occurred in the transmission sector of the industry. Technological advances in transmission have made possible the economic transmission of electric power over long distances at higher voltages.[31] This has

[15] *See* Bernard S. Black & Richard J. Pierce, Jr., The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry, 93 Col. L. Rev. 1339, 1346 (1993) (''Actual costs of nuclear power plants vastly exceeded estimates, sometimes by as much as 1000%.'').

[16] *See* Phillips, *supra* at 13. Fossil fuel-fired plants became subject to increased regulation as a result of the Clean Air Act of 1970, and its 1977 amendments. 42 U.S.C. 7401–7642. In 1971, nuclear plant licensing became subject to the environmental impact statement requirements of the National Environmental Policy Act of 1969. 42 U.S.C. 4332. Following the 1979 accident at the Three Mile Island nuclear plant, nuclear plants also became subject to additional safety regulations, resulting in higher costs. *See* Energy Information Administration, *The Changing Structure of the Electric Power Industry 1970–1991* (March 1993) 35. Between 1976 and 1980, most states and many localities instituted laws governing power plant siting.

[17] Based on retail prices reported in Energy Information Administration (EIA), Monthly Energy Review, January 1995, Table 9.9 (Prices adjusted for inflation using the GDP Deflator (1987 = 100)).

[18] *Id.*

[19] *See* Black & Pierce, *supra* at 1346 (These writeoffs were ''about 17% of the book value of total 1992 utility investment.'').

[20] *Id.*

[21] *Id.* (''The high perceived risk of future disallowances reversed utilities' incentives to overinvest, and made utilities extremely reluctant to build new power plants.'').

[22] *See* Preston Michie, Billing Credits for Conservation, Renewable, and Other Electric Power Resources: an Alternative to Marginal-Cost-Based Power Rates in the Pacific Northwest, 13 Environmental Law 963, 964–65 (1983).

[23] *Id.* at 965.

[24] Energy Information Administration, *The Changing Structure of the Electric Power Industry 1970–1991* (March 1993) 37 (''As larger units were constructed, however, utilities discovered that downtime was as much as 5 times greater for units larger than 600 megawatts than for units in the 100-megawatt range.'')

[25] *Id.; see also* George A. Perrault, Downsizing Generation: Utility Plans for the 1990s, Pub. Util. Fort. 15–16 (Sept. 27, 1990) (''The large base-load generating units that form the backbone of utility systems are almost totally absent from capacity plans for the 1990s.'').

[26] ''From 1982 through 1991, the average capacity of fluidized-bed units increased rapidly to 72 megawatts for 4 units in 1991. The average capacity for the 19 units planned to begin operating in 1992 through 1995 increases to 83 megawatts.'' Energy Information Administration, *The Changing Structure of the Electric Power Industry 1970–1991* (March 1993) 38.

[27] *See* Charles E. Bayless, Less is More: Why Gas Turbines Will Transform Electric Utilities, Pub. Util. Fort. (Dec. 1, 1994) 21.

[28] *Id.* at 24. *See also* Wallace E. Brand, Is Bigger Better? Market Power in Bulk Power Supply: From FDR to NOPR, Pub. Util. Fort. (Feb. 15, 1996) 23 at 25 (while the optimal baseload unit size is about 500 MW for coal-fired steam turbines, the optimal size for gas fired combined-cycle units is about 150 to 200 MW).

[29] FERC staff calculations based in part on combined-cycle plant cost data reported in 1994 FERC Form No. 1 for a sample of units placed in service during 1990–94. Costs vary with regional fuel and construction costs, among other reasons.

[30] Coal and Nuclear plant cost data reported in 1994 FERC Form No. 1 and the EIA report, *Electric Plant Cost and Power Production Expenses 1991*, 1993 DOE/EIA–0455(91), for plants placed in service during 1986–94; *see also* The 1994 Electric Executives' Forum, Bakke (President and CEO of the AES Corporation), Pub. Util. Fort. (June 1, 1994) 45 (''New generation can be built at about 3 cents per kilowatt-hour (U.S. average). Old generation costs about twice that * * *'').

[31] *See* Black & Pierce, *supra* at 1345 (In the late 1960s and 1970s, improved transmission efficiency and development of regional transmission networks ''made it possible to build power plants up to 1000 miles from power users.'').

made it technically feasible for utilities with lower cost generation sources to reach previously isolated systems where customers had been captive to higher cost generation. In addition, the nature and magnitude of coordination transactions [32] have changed dramatically since enactment of the FPA, allowing increased coordinated operations and reduced reserve margins. Substantial amounts of electricity now move between regions, as well as between utilities in the same region. Physically isolated systems have become a thing of the past.

C. The Public Utility Regulatory Policies Act and the Growth of Competition

In enacting PURPA,[33] Congress recognized that the rising costs and decreasing efficiencies of utility-owned generating facilities were increasing rates and harming the economy as a whole.[34] To lessen dependence on expensive foreign oil, avoid repetition of the 1977 natural gas shortage, and control consumer costs, Congress sought to encourage electric utilities to conserve oil and natural gas.[35] In particular, Congress sanctioned the development of alternative generation sources designated as ''qualifying facilities'' (QFs) as a means of reducing the demand for traditional fossil fuels.[36] PURPA required utilities to purchase power from QFs at a price not to exceed the utility's avoided costs and to sell backup power to QFs.[37]

PURPA specifically set forth limitations on who, and what, could qualify as QFs. In addition to technological and size criteria, PURPA set limits on who could own QFs.[38] Notwithstanding these limitations, QFs proliferated. In 1989, there were 576 QF facilities. By 1993, there were more than 1,200 such facilities.[39] For the same time period, installed QF capacity increased from 27,429 megawatts to 47,774 megawatts.[40] The rapid expansion and performance of the QF industry demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power.

During this period, the profile of generation investment began to change, and a market for non-traditional power supply beyond the purchases required by PURPA began to emerge. QFs were limited to cogenerators and small power producers.[41]

However, other non-traditional power producers who could not meet the QF criteria began to build new capacity to compete in bulk power markets, without such PURPA benefits as the mandatory purchase requirements. These producers, known as independent power producers (IPPs), were predominantly single-asset generation companies that did not own any transmission or distribution facilities. While traditional utilities were generally reluctant at that time to invest in new generating facilities under cost of service regulation, utilities increasingly became interested in participating in this new generation sector. They organized affiliated power producers (APPs), with assets not included in utility rate base, and sought to sell power in their own service territories and the territories of other utilities. At the same time, power marketers arose. These entities—owning no transmission or generation—buy and sell power.[42]

There were two major impediments to the development of IPPs and APPs. First, the ownership restrictions of the Public Utility Holding Company Act (PUHCA)[43] severely inhibited these new entities from entering the generation business.[44] Second, these entities needed transmission service in order to compete in electricity markets.

While the Commission had no authority to remove PUHCA restrictions,[45] it encouraged the development of IPPs and APPs, as well as emerging power marketers, by authorizing market-based rates for their power sales on a case-by-case basis and by encouraging more widely available transmission access. From 1989 through 1993, facilities owned by IPPs and other non-traditional generators (other than QFs) increased from 249 to 634 and their installed capacity increased from 9,216 megawatts to 13,004 megawatts.[46] Indeed, ''[i]n 1992, for the first time, generating capacity added by independent producers exceeded capacity added by utilities.'' [47]

Market-based rates helped to develop competitive bulk power markets. A generating utility allowed to sell its power at market-based rates could move more quickly to take advantage of short-term or even long-term market opportunities than those laboring under traditional cost-of-service tariffs, which entail procedural delays in achieving tariff approvals and changes.

In approving these market-based rates, the Commission required, *inter alia*, that the seller and any of its affiliates lack market power or mitigate any market

[32] Coordination transactions are voluntary sales or exchanges of specialized electricity services that allow buyers to realize cost savings or reliability gains that are not attainable if they rely solely on their own resources. For sellers, these transactions provide opportunities to earn additional revenue, and to lower customer rates, from capacity that is temporarily excess to native load capacity requirements.

[33] Pub. L. No. 95–617, 92 Stat. 3117 (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

[34] See generally FERC v. Mississippi, 456 U.S. 742, 745–46 (1982).

[35] The Power Plant and Industrial Fuel Use Act of 1978. Pub. L. No. 95–617, 92 Stat. 3117 (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

[36] QFs include certain cogenerators and small power producers. PURPA also added sections 210, 211, and 212 to the FPA, providing the Commission with authority to approve applications for interconnections and, in limited circumstances, wheeling. However, under section 211, as enacted in PURPA, the Commission could approve an application for wheeling only if it found, *inter alia*, that the order ''would reasonably preserve existing competitive relationships.'' Because of this and other limitations in sections 211 and 212 as originally enacted, the provision was virtually ineffective. Only one section 211 order was ever issued pursuant to the original provision, and it was pursuant to a settlement. *See* Public Service Company of Oklahoma, 38 FERC ¶ 61,050 (1987). As discussed *infra*, section 211 was subsequently revised by the Energy Policy Act of 1992.

[37] 456 U.S. at 750. Congress recognized that encouragement was needed in part because utilities had been reluctant to purchase electric power from, and sell power to, nonutility generators. *Id.* at 750–51.

[38] For example, PURPA provided that a cogeneration facility or small power production facility could not be owned by a person primarily engaged in the generation or sale of electric power (other than from cogeneration or small power production facilities). *See* 16 U.S.C.

[39] Energy Information Administration, *Electric Power Annual 1993* (December 1994) 124 (Table 77).

[40] *Id.* EIA data for 1989 through 1991 was for facilities of 5 megawatts or more and for 1992 and 1993 was for facilities of 1 megawatt or more. A comparison with Table 74 on page 121 for the years 1992 and 1993 reveals that this mixing of data bases is likely of minimal effect.

[41] Generally, the law has imposed an 80 MW cap on small power producers. A limited exception enacted in 1990 permitted small power facilities that could exceed 80 MW and still qualify as QFs under PURPA. This exception was limited to certain solar, wind, waste, and geothermal small power production facilities and only covered applications for certification of facilities as qualifying small power production facilities that were submitted no later than December 31, 1994 and for which construction commences no later than December 31, 1999. *See* Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990, Pub. L. No. 101–575, 104 Stat. 2834 (1990), *amended*, Pub. L. No. 102–46, 105 Stat. 249 (1991).

[42] The first power marketer in the electric industry was Citizens Energy Corporation. *See* Citizens Energy Corporation, 35 FERC ¶ 61,198 (1986). Power marketers take title to electric energy. Power brokers, on the other hand, do not take title and are limited to a matchmaking role.

[43] 15 U.S.C. 79 *et seq.*

[44] As discussed *infra*, Congress eventually provided a means to avoid the PUHCA restrictions by creating exempt wholesale generators (EWGs) in the Energy Policy Act.

[45] The industry was successful to some extent in developing ownership structures that permitted such investment. *See, e.g.*, Commonwealth Atlantic Limited Partnership, 51 FERC ¶ 61,368 at 62,240 and n.20 (1990).

[46] Energy Information Administration, *Electric Power Annual 1993* (December 1994) 124 (Table 77).

[47] Black & Pierce, *supra* at 1349 n.25.

power that they may have possessed.[48] The major concern of the Commission was whether the seller or its affiliates could limit competition and thereby drive up prices. A key inquiry became whether the seller or its affiliates owned or controlled transmission facilities in the relevant service area and therefore, by denying access or imposing discriminatory terms or conditions on transmission service, could foreclose other generators from competing.[49] As we have previously explained:

The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive *ownership* of the facilities. However, market power also may be gained without ownership. Contracts can confer the same rights of control. Entities with contractual control over transmission facilities can withhold supply and extract monopoly prices just as effectively as those who control facilities through ownership.[50]

As entry into wholesale power generation markets increased, the ability of customers to gain access to the transmission services necessary to reach competing suppliers became increasingly important.[51] In addition, beginning in the late 1980s, in order to mitigate their market power to meet Commission conditions, public utilities seeking Commission approval of mergers or consolidations under section 203 of the FPA or Commission authorization for blanket approval of market-based rates for generation services under section 205 of the FPA, filed ''open access'' transmission tariffs of general applicability.[52] The Commission applied its market rate analysis to IOUs, as well as IPPs, APPs, and marketers, and allowed IOUs to sell at market-based rates only if they opened their transmission systems to competitors.[53] The Commission also approved proposed mergers on the condition that the merging companies remedy anticompetitive effects potentially caused by the merger by filing ''open access'' tariffs. These early ''open access'' tariffs required only that the companies provide point-to-point transmission services, which is a much narrower requirement than that being imposed in this Rule and did not require transmission owners to provide to others the same quality of service that they themselves enjoyed.

Following PURPA, the economic and technological changes in the transmission and generation sectors helped give impetus to the many new entrants in the generating markets who could sell electric energy profitably with smaller scale technology at a lower price than many utilities selling from their existing generation facilities at rates reflecting cost. However, it became increasingly clear that the potential consumer benefits that could be derived from these technological advances could be realized only if more efficient generating plants could obtain access to the regional transmission grids. Because many traditional vertically integrated utilities still did not provide open access to third parties and still favored their own generation if and when they provided transmission access to third parties, barriers continued to exist to cheaper, more efficient generation sources.

D. The Energy Policy Act

In response to the competitive developments following PURPA, and the fact that PUHCA and lack of transmission access remained major barriers to new generators, Congress enacted Title VII of the Energy Policy Act of 1992 (Energy Policy Act).[54] A goal of the Energy Policy Act was to promote greater competition in bulk power markets by encouraging new generation entrants, known as exempt wholesale generators (EWGs), and by expanding the Commission's authority under sections 211 and 212 of the FPA to approve applications for transmission services.[55]

An EWG is defined as

Any person determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly through one or more affiliates as defined in [PUHCA] section 2(a)(11)(B), and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale.[56]

If the Commission, upon an application, determines that a person is an EWG, that person will be exempt from PUHCA.[57] This provision removed a significant impediment to the development of IPPs and APPs by allowing them to develop projects as EWGs free from the strictures of PUHCA or the QF PURPA limitations.

While sections 211 and 212, as enacted by PURPA, were intended to provide greater access to the transmission grid, the limitations placed on these sections made them unusable in virtually all circumstances.[58] However, as amended by the Energy Policy Act, these sections now give the Commission broader authority to order transmitting utilities to provide wholesale transmission services, upon application, to any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale.

The Energy Policy Act also added section 213 to the FPA. Section 213(a) requires a transmitting utility that does not agree to provide wholesale transmission service in accordance with a good faith request to provide a written explanation of its proposed rates, terms, and conditions and its analysis of any

[48] *See, e.g.,* Ocean State Power, 44 FERC ¶ 61,261 (1988); Commonwealth Atlantic Limited Partnership, 51 FERC ¶ 61,368 (1990); Citizens Power & Light Company, 48 FERC ¶ 61,210 (1989); Orange and Rockland Utilities, Inc., 42 FERC ¶ 61,012 (1988); Doswell Limited Partnership, 50 FERC ¶ 61,251 (1990) (*Doswel*); and Dartmouth Power Associates Limited Partnership, 53 FERC ¶ 61,117 (1990).

[49] *See, e.g., Doswell,* 50 FERC at 61,757.

[50] Citizens Power & Light Corporation, 48 FERC ¶ 61,210 at 61,777 (1989) (emphasis in original); *see also* Utah Power & Light Company, PacifiCorp and PC/UP&L Merging Corporation, 45 FERC ¶ 61,095 at 61,287–89 (1988), *order on reh'g,* 47 FERC ¶ 61,209, *order on reh'g,* 48 FERC ¶ 61,035 (1989), *remanded in part sub nom.* Environmental Action, Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991), *order on remand,* 57 FERC ¶ 61,363 (1991).

[51] In earlier years, a few customers were able to obtain access as a result of litigation, beginning with the Supreme Court's decision in *Otter Tail Power Company v. United States,* 410 U.S. 366 (1973). Additionally, some customers gained access by virtue of Nuclear Regulatory Commission license conditions and voluntary preference power transmission arrangements associated with federal power marketing agencies. *See, e.g.,* Consumers Power Company, 6 NRC 887, 1036–44 (1977) and The Toledo Edison Company and Cleveland Electric Illuminating Company, 10 NRC 265, 327–34 (1979). *See* Florida Municipal Power Agency v. Florida Power and Light Company, 839 F. Supp. 1563 (M.D. Fla. 1993). *See also* Electricity Transmission: Realities, Theory and Policy Alternatives, The Transmission Task Force Report to the Commission, October 1989, 197.

[52] *See, e.g.,* Public Service Company of Colorado, 59 FERC ¶ 61,311 (1992), *reh'g denied,* 62 FERC ¶ 61,013 (1993); Utah Power & Light Company, *et al.,* Opinion No. 318, 45 FERC ¶ 61,095 (1988), *order on reh'g,* Opinion No. 318–A, 47 FERC ¶ 61,209 (1989), *order on reh'g,* Opinion No. 318–B, 48 FERC ¶ 61,035 (1989), *aff'd in relevant part sub nom.* Environmental Action Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991); Northeast Utilities Service Company (Public Service Company of New Hampshire), Opinion No. 364–A, 58 FERC ¶ 61,070, *reh'g denied,* Opinion No. 364–B, 59 FERC ¶ 61,042, *order granting motion to vacate and dismissing request for rehearing,* 59 FERC ¶ 61,089 (1992), *affirmed in relevant part sub nom.* Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993).

[53] *See, e.g.,* Public Service of Indiana, Inc., 51 FERC ¶ 61,367 (1990), *reh'g denied,* 52 FERC ¶ 61,260 (1990), *appeal dismissed sub nom.* Northern Indiana Public Service Company v. FERC, 954 F.2d 736 (D.C.Cir. 1992).

[54] Pub. L. No. 102–486, 106 Stat. 2776 (1992), codified at, among other places, 15 U.S.C. 79z–5a and 16 U.S.C. 796 (22–25), 824j–l.

[55] *See* El Paso Electric Company and Central and South West Services Inc., 68 FERC ¶ 61,181 at 61,914 (1994) *(CSW); see also* Paul Kemezis, FERC's Competitive Muscle: The Comparability Standard, Electrical World 45 (Jan. 1995) (''In EPAct, Congress made it clear that the electric-power industry was to move toward a fully competitive market system, but left most of the implementation to FERC.'').

[56] 15 U.S.C. 79z–5a.

[57] 15 U.S.C. 79z–5a(e).

[58] *See supra* note 36.

physical or other constraints.[59] Section 213(b) required the Commission to enact a rule requiring transmitting utilities to submit annual information concerning potentially available transmission capacity and known constraints.[60]

E. The Present Competitive Environment

Following the Energy Policy Act, the Commission established rules: (1) For certain generators to obtain EWG status and thus an exemption from PUHCA;[61] and (2) that required transmission information availability. The Commission also pursued a number of initiatives aimed at fostering the development of more competitive bulk power markets, including aggressive implementation of section 211, a new look at undue discrimination under the FPA, easing of market entry for sellers of generation from new facilities, and initiation of a number of industry-wide reforms. As stated by the Commission, in recognition of the Congressional goal in the Energy Policy Act of creating competitive bulk power markets:

Our goal is to facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa.[62]

1. Use of Sections 211 and 212 to Obtain Transmission Access

The Commission has aggressively implemented sections 211 and 212 of the FPA, as amended by the Energy Policy Act, in order to promote competitive markets.[63] When wheeling requests under sections 211 and 212 have been made, the Commission has required wheeling in almost all of the requests it has processed. To date, the Commission has issued orders (proposed or final) requiring wheeling in 12 of the 14 cases it has acted on.[64]

As a general matter, section 211 has permitted some inroads to be made by customers in obtaining transmission service from public utilities that historically have declined to provide access to their systems, or have offered service only on a discriminatory basis. Under section 211, the Commission has granted requests for the broader type of service that most utilities historically have refused to provide—network service. Although transmission owners have provided limited amounts of unbundled point-to-point transmission service, third-party customers have not been able to obtain the flexibility of service that transmission owners enjoy.

In *Florida Municipal*, a section 211 case, the Commission ordered ''network,'' rather than the narrower ''point-to-point,'' service.[65] Network service permits the applicant to fully integrate load and resources on an instantaneous basis in a manner similar to the transmission owner's integration of its own load and resources. At the same time, the Commission made the generic finding that the availability of transmission service will enhance competition in the market for power supplies and lead to lower costs for consumers. The Commission explained that as long as the transmitting utility is fully and fairly compensated and there is no unreasonable impairment of reliability, transmission service is in the public interest.[66]

As discussed *infra*, based on the mounting competitive pressures in the industry and rapidly evolving markets, we have concluded that section 211 alone is not enough to eliminate undue discrimination. The comments received on the proposed rules, discussed in detail *infra*, confirm this conclusion. The significant time delays involved in filing an individual service request for bilateral service under section 211 place the customer at a severe disadvantage compared to the transmission owner and can result in discriminatory treatment in the use of the transmission system. It is an inadequate procedural substitute for readily available service under a filed non-discriminatory open access tariff. As the Commission noted in *Hermiston Generating Company*, ''[t]he ability to spend time and resources litigating the rates, terms and conditions of transmission access is not equivalent to an enforceable voluntary offer to provide comparable service under known rates, terms and conditions.''[67]

2. Commission's Comparability Standard

In the Spring of 1994, the Commission began to address the problem of the disparity in transmission service that utilities provided to third parties in comparison to their own uses of the transmission system. In the seminal case in this area, *American Electric Power Service Corporation* (*AEP*), the company voluntarily proposed a tariff of general applicability that would offer firm, point-to-point transmission service for a minimum of one month.[68] The Commission accepted the proposed transmission tariff for filing and suspended its effectiveness for one day, subject to refund.[69] Rehearing requests challenged the Commission's summary approval of the restriction of service to point-to-point as being discriminatory and anticompetitive.[70] The rehearing

[59] *See* Policy Statement Regarding Good Faith Requests for Transmission Services and Responses by Transmitting Utilities Under Sections 211(a) and 213(a) of the Federal Power Act, as Amended and Added by the Energy Policy Act of 1992, 58 FR 38964 (July 21, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,975 (1993) (Policy Statement Regarding Good Faith Requests for Transmission Services).

[60] *See* New Reporting Requirements Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities Under the Energy Policy Act of 1992, and Conforming and Other Changes to Form No. FERC–714, 58 FR 52420 (October 8, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,980 (Order No. 558), *reh'g denied*, Order No. 558–A, 65 FERC ¶ 61,324 (1993), *regulations modified*, 59 FR 15333 (April 1, 1994), FERC Stats. & Regs., Regulations Preambles ¶ 30,993.

[61] *See* Order No. 550, Filing Requirements and Ministerial Procedures for Persons Seeking Exempt Wholesale Generator Status, 58 FR 8897 (February 18, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,964, *order on reh'g*, Order No. 550–A, 58 FR 21250 (April 20, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,969 (1993). As recognized by Congress and the Commission, availability of transmission information is critical in developing competitive markets. *See supra* notes 59 and 60. This opened the ''black box'' of information that previously was available only to transmission owners.

[62] *See* Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, 59 FR 35274 (July 11, 1994), FERC Stats. & Regs., Proposed Regulations ¶ 32,507 at 32,866 (Stranded Cost NOPR); American Electric Power Service Corporation, 67 FERC ¶ 61,168, *clarified*, 67 FERC ¶ 61,317 (1994).

[63] 16 U.S.C.A. 824j–824k (West 1985 and Supp. 1994).

[64] *See, e.g.*, final orders issued in City of Bedford, 68 FERC ¶ 61,003 (1994), *reh'g denied*, 73 FERC ¶ 61,322 (1995); Florida Municipal Power Agency v. Florida Power & Light Company, 67 FERC ¶ 61,167 (1994), *order on reh'g*, 74 FERC ¶ 61,006 (1996); Minnesota Municipal Power Agency, 68 FERC ¶ 61,060 (1994); and Tex-La Electric Cooperative of Texas, 69 FERC ¶ 61,269 (1994); *see also* Appendix A.

[65] *See* Florida Municipal Power Agency v. Florida Power & Light Company, 65 FERC ¶ 61,125, *reh'g dismissed*, 65 FERC ¶ 61,372 (1993), *final order*, 67 FERC ¶ 61,167 (1994), *order on reh'g*, 74 FERC ¶ 61,006 (1996). The Commission has ''characterized point-to-point service as involving designated points of entry into and exit from the transmitting utility's system, with a designated amount of transfer capability at each point.'' El Paso Electric Company v. Southwestern Public Service Company, 68 FERC ¶ 61,182 at 61,926 n.9 (1994) (*citing* Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,768 (1993), *reh'g dismissed*, 68 FERC ¶ 61,399 (1994)). Network service allows more flexibility by allowing a transmission customer to use the entire transmission network to provide generation service for specified resources and specified loads without having to pay multiple charges for each resource-load pairing.

[66] *Florida Municipal*, 67 FERC at 61,477.

[67] 69 FERC ¶ 61,035 at 61,165 (1994), *reh'g denied*, 72 FERC ¶ 61,071 (1995); *see also* Southwest Regional Transmission Association, 69 FERC ¶ 61,100 at 61,398 (1994), *order on compliance filing*, 73 FERC ¶ 61,147 (1995) (*SWRTA*).

[68] 64 FERC ¶ 61,279 (1993), *reh'g granted*, 67 FERC ¶ 61,168, *clarified*, 67 FERC ¶ 61,317 (1994).

[69] The Commission explained that AEP could limit the service it was offering because it was ''providing the service voluntarily under a tariff of general applicability.'' 64 FERC at 62,978.

[70] *AEP*, 67 FERC at 61,489.

requests argued that the tariff should be expanded to include network services such as those used by the transmission owner. On rehearing, the Commission announced a new standard for evaluating claims of undue discrimination.

The Commission found that a voluntarily offered, new open access transmission tariff that did not provide for services comparable to those that the transmission owner provided itself was unduly discriminatory and anticompetitive.[71] In reaching that conclusion, the Commission broadened its undue discrimination analysis (which traditionally had focused on the rates, terms, and conditions faced by similarly situated third-party customers) to include a focus on the rates, terms, and conditions of a utility's own uses of the transmission system:

(A)n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system.[72]

Refocusing the analysis was necessitated by the changing conditions in the electric utility industry, including the emergence of non-traditional suppliers and greater competition in bulk power markets. Because a transmission provider may use its system in different ways (*e.g.*, to integrate load and resources when serving retail native load, to make off-system sales or purchases, or to serve wholesale requirements customers), the Commission set for hearing the factual issues associated with identifying those uses, as well as any potential impediments or consequences to providing comparable services to third parties.[73]

After *AEP*, the Commission applied this comparability standard to a proposed open access transmission tariff that was filed by Kansas City Power & Light Company (KCP&L) in support of a proposal to sell generation at market-based rates.[74] The Commission explained that, in light of *AEP*, the utility's proposed open access transmission tariff (which provided only for point-to-point service) did not adequately mitigate its transmission market power so as to justify allowing the requested market-based rates. KCP&L could charge market-based rates for sales only if it modified its proposed transmission tariff to reflect the *AEP* comparability standard.

Since then, the Commission has required comparable service in a variety of contexts, and has set for hearing the factual issues associated with comparable service. For example, the Commission found that market power can be adequately mitigated only if a merged company offers transmission services in accordance with the *AEP* comparability standard.[75] The Commission further held that, even if a merger does not result in an increase in market power, the merger would not be consistent with the public interest under section 203 of the FPA unless the merged company offers comparable transmission services, as defined in *AEP*.[76] The Commission therefore announced a transmission comparability requirement for all new mergers:

Given the transition of the electric utility industry as a whole, we conclude that, absent other compelling public interest considerations, coordination in the public interest can best be secured only if merging utilities offer comparable transmission services.[77]

In *Heartland Energy Services, Inc.*,[78] the Commission applied its comparability standard to an affiliated electric power marketer seeking blanket authorization to sell electricity at market-based rates. The Commission explained that

For all future cases involving blanket approval of market-based rates an offer of comparable transmission services will be required before the Commission will be able to find that transmission market power has been adequately mitigated. In the context of an affiliated power marketer, this means that all of its affiliated utilities must have a comparable transmission tariff on file.[79]

The Commission also denied a request by a company affiliated with a transmission-owning utility seeking permission to sell power at market-based rates to a particular customer. The denial was without prejudice to refiling such a request in a new section 205 proceeding, but only after the affiliated transmission-owning utility filed a comparable transmission service tariff.[80] The Commission added that it

Will require comparability in any situation in which a seller seeking market-based rates is affiliated with an owner or controller of transmission facilities.[81]

The Commission has also stated that ''it will henceforth apply the transmission comparability standard announced in the *AEP* case to all transmitting utility members of an RTG.''[82]

The Commission further declared that comparable services must be provided through ''open access'' tariffs rather than only on a contract-by-contract basis:

(T)ariffs are essential to the provision of comparable services. Tariffs set out the services that are available and the terms and conditions under which those services will be made available * * *. (In contrast), a negotiation process creates uncertainty and imposes on customers delay and other transaction costs that the transmitting utility members of an RTG do not incur when using the transmission for their own benefit. Moreover, the ability to execute separate transmission agreements with different but similarly situated customers is the ability to unduly discriminate among them. A tariff ensures against such discrimination in the RTG.[83]

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[71] With respect to anticompetitive effects, the Commission explained that it has ''adhered to the Supreme Court's determination that the Commission's 'important and broad regulatory power * * * carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to sections 202 and 203, and under like directives contained in sections 205, 206 and 207.' Gulf States Utilities Company v. FPC, 411 U.S. 747, 758–59 (1972).'' *Id.* at 61,490 (footnote omitted). The Commission reaffirmed that it would examine how best to fulfill this responsibility, as well as its responsibility to prevent undue discrimination, in light of the changing conditions in the electric utility industry. *Id.*

[72] *Id.* at 61,490.

[73] *Id.* at 61,490–91.

[74] *See* Kansas City Power & Light Company, 67 FERC ¶ 61,183 (1994), *reh'g pending.*

[75] *E.g., CSW, supra*, 68 FERC at 61,914.

[76] *Id.*

[77] *Id.* at 61,915 (footnote omitted).

[78] 68 FERC ¶ 61,223 (1994).

[79] Id. at 62,060. In InterCoast Power Marketing Company, 68 FERC ¶ 61,248, *clarified*, 68 FERC ¶ 61,324 (1994), the Commission rejected an affiliated marketer's proposal to sell at market rates without its affiliate utility offering comparable transmission services. The Commission stated that the only way to ensure that InterCoast does not have transmission market power is to require its affiliated public utility to offer comparable transmission services. *See also* LG&E Power Marketing Inc., 68 FERC ¶ 61,247 at 62,120–21 (1994). The Commission added that this is consistent with encouraging competitive bulk power markets as envisioned by the Energy Policy Act of 1992. *Id.* at 62,132.

[80] *See* Hermiston Generating Company, 69 FERC ¶ 61,035 at 61,164 (1994), *reh'g pending.* The Commission subsequently accepted the rates on a cost basis. *See* Letter Order dated November 10, 1994.

[81] *Id.* at 61,165.

[82] *See SWRTA*, 69 FERC at 61,397; *see also* PacifiCorp, the California Municipal Utilities Association, and the Independent Energy Producers (on behalf of Western Regional Transmission Association), 69 FERC ¶ 61,099, *order on reh'g*, 69 FERC ¶ 61,352 (1994), *order on compliance filing*, 71 FERC ¶ 61,158 (1995) (*WRTA*). An RTG is a regional transmission group. It is defined as ''a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional (and inter-regional.'' Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (August 5, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,976 at 30,870 n. 4 (RTG Policy Statement).

[83] *SWRTA*, 69 FERC at 61,398.

Thus, the Commission required the RTGs to amend their bylaws to commit all transmitting utility members to offer comparable transmission services to other RTG members pursuant to a transmission tariff or tariffs.

As discussed below, since the *AEP* comparability standard was announced, the Commission has set for hearing 44 open access tariffs to determine what constitutes comparable service. This number includes tariffs filed subsequent to the Open Access NOPR. All tariffs have now been made subject to the outcome of the Final Rule.

3. Lack of Market Power in New Generation

In 1994 in the *KCP&L* case, discussed in the prior section, the Commission continued to recognize that transmission remains a natural monopoly. However, it found that, in light of the industry and statutory changes that now allow ease of market entry, no wholesale seller of generation has market power in generation from *new* facilities.[84] In particular, the Commission explained that it had previously noted in *Entergy Services, Inc.* that

> There was significant evidence that non-traditional power project developers, including qualifying facilities and independent power projects, are becoming viable competitors in long-run markets.[85]

The Commission further explained that since *Entergy*, Congress had enacted the Energy Policy Act, which had lowered barriers to the entry of new suppliers by creating a new class of power suppliers—EWGs—that are exempt from the provisions of PUHCA.[86] The Commission concluded that, in considering market-based rate proposals for generation sales, it need only focus on market power in transmission, generation market power in short-run markets, and other barriers to entry.[87]

4. Further Commission Action Addressing a More Competitive Electric Industry

To address the fact that the electric industry is becoming more competitive, and to remove barriers that might inhibit a more competitive industry, the Commission has initiated a number of proceedings: (1) Stranded Cost NOPR,[88] (2) Transmission Pricing Policy Statement,[89] (3) Pooling Notice of Inquiry,[90] (4) Regional Transmission Group (RTG) Policy Statement,[91] and (5) Notice of Inquiry on Merger Policy.[92]

In the Stranded Cost NOPR the Commission recognized that the trend toward greater transmission access and the transition to a fully competitive bulk power market could cause some utilities to incur stranded costs as wholesale requirements customers (or retail customers) use their supplier's transmission to purchase power elsewhere. As the Commission noted, a utility may have built facilities or entered into long-term fuel or purchased power supply contracts with the reasonable expectation that its customers would renew their contracts and would pay their share of long-term investments and other incurred costs. If the customer obtains another power supplier, the utility may have stranded costs. If the utility cannot locate an alternative buyer or somehow mitigate the stranded costs, the Commission explained that ''the costs must be recovered from either the departing customer or the remaining customers or borne by the utility's shareholders.'' [93] Accordingly, the Commission proposed to establish provisions concerning the recovery of wholesale and retail stranded costs by public utilities and transmitting utilities.

In the Transmission Pricing Policy Statement, the Commission announced a new policy providing greater flexibility in the pricing of transmission services provided by public utilities and transmitting utilities. The Commission traditionally had allowed only postage-stamp, contract-path pricing.[94] Under the new policy, we will permit a variety of proposals, including distance sensitive and flow-based pricing, which may be more suitable for competitive wholesale power markets.[95] The Commission explained that this ''(g)reater pricing flexibility is appropriate in light of the significant competitive changes occurring in wholesale generation markets, and in light of our expanded wheeling authority under the Energy Policy Act of 1992.'' [96] However, the Commission explained that any new transmission pricing proposal must meet the Commission's *AEP* comparability standard. The Commission further explained that comparability of service applies to price as well as to terms and conditions.[97]

The Commission issued the Pooling Notice of Inquiry to receive comments on traditional power pools and on alternative power pooling institutions that are being explored in today's more competitive environment. The Commission expressed concern that

> (G)iven the ongoing changes in the competitive environment of the electric utility industry—in particular, the potential for substantially increased access to transmission—we must consider whether we are appropriately balancing our dual objectives of promoting coordination and competition.[98]

Accordingly, the Commission explained that it wished to look at alternative power pooling institutions and to re-examine the role of more traditional power pools in today's environment of increased competition. In particular the Commission expressed its intent to ensure that its policies ''are consistent with the development of a competitive bulk power market.'' [99]

In the RTG Policy Statement, the Commission announced a policy encouraging the development of RTGs. The Commission explained that a primary purpose of RTGs is to facilitate transmission access for potential users and voluntarily resolve disputes over such service. The Commission has approved the formation of three

[84] *KCP&L*, 67 FERC ¶ 61,183 (1994).

[85] *Id.* at 61,557 (citing Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,756 and nn. 63 and 65 (*Entergy*)).

[86] *Id.* The Commission added that ''after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets.'' *Id.*

[87] *Id.*

[88] FERC Stats. & Regs. ¶ 32,507 (1994).

[89] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 59 FR 55031 (November 3, 1994), FERC Stats. & Regs., Regulations Preambles ¶ 31,005 (Transmission Pricing Policy Statement).

[90] Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, 59 FR 54851 (October 26, 1994), FERC Stats. & Regs., Notices ¶ 35,529 (1995) (Pooling Notice of Inquiry).

[91] FERC Stats. & Regs. ¶ 30,976 (RTG Policy Statement).

[92] FERC Stats. & Regs. ¶ 35,531 (1996).

[93] FERC Stats. & Regs. ¶ 32,507 at 32,864.

[94] Most transmission contracts set a single price for energy flow over a utility's transmission system. This single-price policy is called ''postage stamp'' pricing because the rate does not depend on how far the power moves within a company's transmission system. If power flows through several companies, traditional industry practice is to specify that power flows along a ''contract path'' consisting of the transmission-owning utilities between the ultimate receipt and delivery points. *See* Indiana Michigan Power Company, 64 FERC ¶ 61,184 at 62,545 (1993).

[95] Unlike with postage stamp pricing, with distance-sensitive pricing the cost of moving power through a company depends on how far the power moves within the company. In contrast to contract path pricing, flow-based pricing establishes a price based on the costs of the various parallel paths actually used when the power flows. Because flow-based pricing can account for all parallel paths used by the transaction, all transmission owners with facilities on any of the parallel paths could be compensated for the transaction.

[96] FERC Stats. & Regs. ¶ 31,005 at 31,136.

[97] *Id.* at 31,142.

[98] FERC Stats. & Regs. ¶ 35,529 at 35,715.

[99] *Id.* at 35,714. As explained below, the Commission held technical conferences on issues surrounding power pools and competition.

RTGs.[100] One of the conditions is that each RTG member must offer comparable transmission services by tariff to other RTG members.

In the merger NOI, the Commission indicated that it will review whether its criteria and policy for evaluating mergers need to be modified in light of the changing circumstances occurring in the electric industry.

In addition to the Commission's actions, a number of states have initiated proceedings concerning retail wheeling or proposed legislation for retail wheeling, that is, for ultimate consumers to choose their supplier of power, or other restructuring proposals.[101]

5. Events Since Issuance of Open Access NOPR

Since issuance of the Open Access NOPR, public utilities have filed, in some form or another, 47 open access tariffs. In acting on those filings, the Commission has made all of the non-rate terms and conditions of those proposed tariffs subject to the outcome of this Final Rule.[102]

Over the last year, the Commission also has received and analyzed more than 20,000 pages of comments that were received from over 400 commenters, as well as additional information provided by industry participants at a number of Commission-initiated technical conferences.[103] Those technical conferences addressed several issues—ancillary services, pro forma tariffs, power pools, and ISOs—and provided significant input to the Commission's formulation of this Final Rule.

F. Need for Reform

The many changes discussed above have converged to create a situation in which new generating capacity can be built and operated at prices substantially lower than many utilities' embedded costs of generation. As discussed above, new generation facilities can produce power on the grid at a cost of less than 3 cents per kWh to 5 cents per kWh, yet the costs for large plants constructed and installed over the last decade were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.

Non-traditional generators are taking advantage of this opportunity to compete. Indeed, the non-traditional generators' share of total U.S. electricity generation increased from 4 percent in 1985 to 10 percent in 1993.[104] Much of this increased share of generation is the result of competitive bidding for new generation resources that has occurred in 37 states. Since 1984, almost 4,000 projects, representing over 400,000 MW, have been offered in response to requests. Over 350 projects have been selected to supply 20,000 MW, and, of these, 126 are now online producing almost 7,800 MW of power.[105]

In addition, the cost of utility-generated electricity differs widely across the major regions of the United States. Average utility rates range from 3 to 5 cents in the Northwest to 9 to 11 cents in California. Electricity consumers are demanding access to lower cost supplies available in other regions of the United States, and access to the newer, lower cost generation resources. Therefore, it is important that the non-traditional generators of cheaper power be able to gain access to the transmission grid on a non-discriminatory open access basis.

The Commission's goal is to ensure that customers have the benefits of competitively priced generation. However, we must do so without abandoning our traditional obligation to ensure that utilities have a fair opportunity to recover prudently incurred costs and that they maintain power supply reliability. As well, the benefits of competition should not come at the expense of other customers. The Commission believes that requiring utilities to provide non-discriminatory open access transmission tariffs, while simultaneously resolving the extremely difficult issue of recovery of transition costs (discussed *infra*), is the key to reconciling these competing demands.

Non-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition.[106] Transmitting utilities own the transportation system over which bulk power competition occurs and transmission service continues to be a natural monopoly. Denials of access (whether they are blatant or subtle), and the potential for future denials of access, require the Commission to revisit and reform its regulation of transmission in interstate commerce. As discussed in detail in Section IV.B., such action is required by the FPA's mandate that the Commission remedy undue discrimination.

Since the time the NOPR issued, the Commission staff has completed an FEIS that provides a quantitative estimate of some of the cost savings expected from this Rule: approximately $3.8 to $5.4 billion per year. Other non-quantifiable benefits are also expected from this Rule and include: (1) Better use of existing assets and institutions; (2) new market mechanisms; (3) technical innovation; and (4) less rate distortion. These potential benefits to the Nation's electricity consumers and the economy as a whole confirm the need to take generic action to remove barriers to competition. In what follows, we set out the changes necessary to remedy undue discrimination and to ensure a fair transition to a more competitive regulatory regime.

IV. Discussion

A. Scope of the Rule

1. Introduction

The Commission has determined that non-discriminatory open access transmission services (including access to transmission information) and stranded cost recovery are the most critical components of a successful transition to competitive wholesale electricity markets. These issues are the focal point of this Rule, the accompanying rule on open access same-time information systems, and the accompanying proposed rule on capacity reservation tariffs.

[100] *See WRTA* and *SWRTA, supra*, and Northwest Regional Transmission Association, 71 FERC ¶ 61,397 (1995).

[101] At least 12 states have retail wheeling proposals, legislation, or pilot programs underway—Alabama, California, Connecticut, Illinois, Massachusetts, Michigan, New Hampshire, New York, Ohio, Rhode Island, Vermont, and Wisconsin. At least 14 other states are investigating retail wheeling. Currently, according

to a report of the NARUC-affiliated National Council on competition and the Electric Industry, 41 States are actively involved in investigating whether and how to restructure their respective electric power markets. Of this total, 29 State regulatory authorities * * * have initiated investigations. In addition, five State legislatures are involved in similar investigations, while seven other States have joint regulatory/legislative proceedings underway.

Testimony of the Honorable Cheryl L. Parrino, Chair of the Wisconsin Public Service Commission, on behalf of the National Association of Regulatory Utility Commissioners, before the United States Senate Committee on Energy and Natural Resources (March 6, 1996).

[102] *See* American Electric Power Service Corporation, *et al.*, 72 FERC ¶ 61,287 at 61,238 (1995).

[103] Attached to this Final Rule as Appendix B is a list of commenters and the abbreviations used to designate them, including those commenters that filed late.

[104] Energy Information Administration, *Performance Issues for a Changing Electric Power Industry* (January 1995) 10 and (Figure 5).

[105] Current Competition, November 1994, Vol. 5, No. 8, at 8.

[106] As discussed above, a significant number of public utilities still do not have any form of an ''open access'' tariff on file with the Commission and no public utility has on file a non-discriminatory open access tariff as defined by this Rule.

In undertaking these initiatives, however, we are mindful that they are part of a broader picture of evolving issues affecting the electric industry and that other Commission policies will play an important role in ensuring the full development of competitive markets. Among the many issues that are important to competitive bulk power markets are: independent system operators (ISOs); regional transmission groups; generation market power; utility merger policy; and the development of innovative transmission pricing alternatives, such as flow-based, distance-sensitive transmission pricing methodologies that reflect incremental costs. In particular, we believe that ISOs have great potential to assist us and the industry to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power. Although we discuss some of these issues in this Rule, we will further develop our policies in other proceedings as well to accommodate and encourage more efficient market structures.

We now address the comments received on the scope of the proposed rulemaking.

2. Functional Unbundling

In the NOPR, the Commission preliminarily found that functional unbundling of wholesale generation and transmission services is necessary to implement non-discriminatory open access transmission.[107] At the same time, the Commission explained that the proposed rule would accommodate, but not require, corporate unbundling (which could include selling generation or transmission assets to a non-affiliate (divestiture) or the less aggressive step of establishing separate corporate affiliates to manage a utility's transmission and generation assets). However, we invited comments on functional unbundling and asked whether it is a strong enough measure to ensure non-discriminatory open access transmission without some form of corporate restructuring.

Comments

Commenters take both sides on whether functional unbundling is sufficient to assure non-discriminatory open access transmission or whether a stronger measure, such as corporate unbundling, is needed.

Supporting Functional Unbundling

Various commenters, including utilities and state commissions, generally support functional unbundling as sufficient to assure non-discriminatory open access transmission and oppose requiring corporate unbundling or divestiture.[108] Several commenters state that functional unbundling will remedy discrimination without creating the inefficiencies and additional costs that corporate restructuring would create.[109]

A number of other commenters argue that the Commission has no authority under the FPA to require divestiture of transmission assets.[110] Several of these commenters assert that, even if the Commission has the authority, the electric industry, unlike the natural gas industry, is not ready for mandated corporate unbundling because electric utilities still serve a high percentage of retail customers and own large amounts of the generating capacity. They assert that transmission system operation requires the operator to have control over much of the generating capacity.

Various other commenters also support functional unbundling, but believe that safeguards are needed to make it work.[111] Power Marketing Association, for example, suggests a number of safeguards: adoption of cost allocation mechanisms to ensure that utilities do not shift costs from generation to transmission; random audits of utility books; a requirement that each utility file a code of conduct that provides for maximum separation of generation and transmission functions; and active oversight and complaint procedures with strong penalties for abuse. OK Com and GA Com believe that functional unbundling along with the safeguard of the Commission's complaint process will provide sufficient incentive for non-discriminatory open access transmission.

Supporting Corporate Unbundling

A number of commenters see weaknesses in functional unbundling and argue that some form of corporate unbundling is necessary to assure non-discriminatory open access transmission.[112] American Forest & Paper says that there is affiliate abuse in the gas industry and argues that the electric industry presents even more serious potential for abuse because it is still dominated by vertically integrated utilities.[113] UAMPS asserts that functional unbundling is insufficient because the utility will still favor itself on issues related to transmission planning, capital investment, and operation and maintenance and replacement costs.

NIEP argues that divestiture of generation assets from transmission and distribution is the preferred mechanism for mitigating market power. It further suggests that if corporate divestiture is not feasible the Commission should

> Seek to achieve ''virtual divestiture'' by requiring that the utility generation function be separated from transmission and distribution functions in a separate corporate affiliate, or business unit, and that affiliate transaction rules be established to guard against possible abuses.[114]

It maintains that the Commission has broad authority to protect against undue discrimination and anticompetitive behavior and can order divestiture if such action is required to remedy such behavior.[115]

FTC and DOJ argue that operational unbundling, an example of which is the formation of an independent system operator (ISO), likely would be more effective than functional unbundling and less costly than industry-wide divestiture.[116] FTC describes operational unbundling as ''structural institutional arrangements, short of divestiture, that would separate operation of the transmission grid and access to it from economic interests in generation.'' It gives as an example the California proposal under which utilities would continue to own transmission lines, but an independent system operator would have operational control. DOJ also suggests ''a separate authority'' to

[107] FERC Stats. & Regs. ¶32,514 at 33,080.

[108] *E.g.*, Ohio Edison, UtiliCorp, Pennsylvania P&L, Atlantic City, Montana Power, IL Com, Seattle, OK Com, TX Industrials, MidAmerican, Southwestern, Southern, DOD, Public Service Co of CO, SC Public Service Authority, Florida Power Corp, DOE, WP&L, Com Ed, SBA, Consumers Power, CA Com, UT Com, Houston L&P, KCPL, EEI.

[109] *E.g.*, Florida Power Corp, El Paso, PSNM, and SC Public Service Authority.

[110] *E.g.*, Southwestern, PECO, El Paso, Florida Power Corp, NSP, Public Service E&G, MidAmerican.

[111] *E.g.*, NRECA, IN Com, Power Marketing Association, TDU Systems, NorAm, Turlock, Texaco, Utility Shareholders, NSP, El Paso, Utility Investors Analysts, PECO, Florida Power Corp, UT Com, Sierra, Carolina P&L, SoCal Gas, OK Com, FL Com, Southern.

[112] *E.g.*, American Forest & Power, American National Power, ND Com, IL Com, UAMPS, NIEP, APPA, Public Power Council, Municipal Energy Agency Nebraska, Missouri Basin MPA, Texaco, Direct Services Industries, Calpine, CCEM, Wisconsin Coalition, VT DPS.

[113] *See also* American National Power, ND Com, Calpine.

[114] NIEP Initial Comments at 4.

[115] *See also* Municipal Energy Agency Nebraska, Direct Services Industries.

[116] Others oppose operational unbundling. *See, e.g.*, Carolina P&L, Salt River.

manage the grid and access to the grid, joint ventures, and voluntary pooling arrangements. These commenters argue that operational unbundling would be easier to enforce than functional unbundling.

DOE states that separation of the control of transmission from vertically-integrated companies does not necessarily require a poolco or any particular market mechanism. It suggests the possibility of an ISO that is functionally separate from any buyer or seller of generation, but would not perform all the functions of a poolco.

United Illuminating supports ''operational unbundling'' that would either (1) eliminate vertical integration and divestiture of transmission assets, leading to the formation of a regional transmission company, or (2) develop a regional contractual approach to transmission services that eliminates the transmission owner's market power and fairly allocates support of the transmission facilities between native load and third-party users of the system.

Commission Conclusion

We conclude that functional unbundling of wholesale services is necessary to implement non-discriminatory open access transmission and that corporate unbundling should not now be required. As we explained in the NOPR, functional unbundling means three things:

(1) A public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others;

(2) A public utility must state separate rates for wholesale generation, transmission, and ancillary services;

(3) A public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.

We believe that these requirements are necessary to ensure that public utilities provide non-discriminatory service.[117] These requirements also will give public utilities an incentive to file fair and efficient rates, terms, and conditions, since they will be subject to those same rates, terms, and conditions.

However, we recognize that additional safeguards are necessary to protect against market power abuses. Functional unbundling will work only if a strong code of conduct (including a requirement to separate employees involved in transmission functions from those involved in wholesale power merchant functions) is in place. In the RINs NOPR, the Commission proposed a code of conduct that would apply to all public utility transmission providers. As the Commission explained,

> [T]his code of conduct would require, among other matters, a separation of the utilities' transmission system operations and wholesale marketing functions, and would define permissible and impermissible contacts between employees that conduct wholesale generation marketing functions and employees that handle transmission system operations and reliability in the system control center or at other facilities or locations.[118]

Adoption of this code of conduct, discussed in detail in the accompanying final rule on OASIS,[119] is needed to ensure that the transmission owner's wholesale marketing personnel and the transmission customer's marketing personnel have comparable access to information about the transmission system.

As noted by OK Com and GA Com, a further safeguard—section 206—is available if a public utility seeks to circumvent the functional unbundling requirements. Under section 206, any person is free to file a complaint with the Commission detailing any alleged misbehavior on the part of the public utility or its affiliates concerning matters subject to our jurisdiction under the FPA. Similarly, the Commission may, on its own motion, initiate a proceeding to investigate the practices of the public utility and its affiliates.

We believe that functional unbundling, coupled with these safeguards, is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. In the absence of evidence that functional unbundling will not work, we are not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time.

Several commenters discuss the need to encourage or even to require ISOs in the context of functional unbundling. We believe that ISOs have the potential to provide significant benefits (*e.g.*, to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power) and will further our goal of achieving a workably competitive market. As we learned at our technical conference on power pools, many utilities are examining ISOs and corporate unbundling in various shapes and forms, particularly in the context of power pools. We discuss ISOs extensively in our section on power pools where we believe they will have an important role to play. However, in the context of individual utility transactions, we believe that the less intrusive functional unbundling approach outlined above is all that we must require at this time. Nevertheless, we see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace.

As a further precaution against discriminatory behavior, we will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, we will analyze all alternative proposals, including formation of ISOs, and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, we will reevaluate our position and decide whether other mechanisms, such as ISOs, should be required.

Finally, while we are not now requiring any form of corporate unbundling, we again encourage utilities to explore whether corporate unbundling or other restructuring mechanisms may be appropriate in particular circumstances. Thus, we intend to accommodate other mechanisms that public utilities may submit, including voluntary corporate restructurings (*e.g.*, ISOs, separate corporate divisions, divestiture, poolcos), to ensure that open access transmission occurs on a non-discriminatory basis. We also will continue to monitor—and stand ready to work with parties engaging in—innovative restructuring proposals occurring around the country.

3. Market-Based Rates

a. Market-Based Rates for New Generation

In the NOPR, the Commission proposed to codify its determination in *Kansas City Power & Light Company*[120]

[117] When and how functional unbundling is to be achieved for requirements transactions and for various types of coordination arrangements, including power pools, is discussed at Sections IV.A.5 and IV.F. Functional unbundling of ancillary services is discussed in Section IV.D.

[118] Real-Time Information Networks and Standards of Conduct, Notice of Proposed Rulemaking, 60 FR 66182 (December 21, 1995), FERC Stats. & Regs., Proposed Regulations ¶ 32,516 at 33,170 (1995).

[119] The final rule on information systems no longer uses the terminology RINs. The new terminology used is OASIS—Open Access Same-time Information System—which we will use in this Final Rule.

[120] 67 FERC ¶ 61,183 at 61,557 (1994), *reh'g pending (KCP&L).*

that the generation dominance standard for market-based sales from new capacity be dropped.[121] The proposed new section 35.27 would provide:

Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity first placed in service on or after June 10, 1996.[122]

However, this proposal would not affect the Commission's continuing authority to look at whether an applicant and its affiliates could erect other barriers to entry and whether there may be affiliate abuse or reciprocal dealing.[123]

Comments

A number of commenters support the Commission's determination in *KCP&L* [124] and several of them explicitly support the Commission's proposed codification.[125] EEI asserts that more than 50 percent of new generation is from non-utility sources and that recent competitive solicitations for new capacity have been greatly over-subscribed. Entergy argues that there is no evidence in any proceeding thus far of a market power problem in long-run markets.

Other commenters, however, oppose codifying *KCP&L*.[126] They believe that market power in long-run markets exists for both new and old generation due to, for example, constraints on interface capabilities and unduly long notice periods for replacement of purchases. They argue that there is not enough of a distinction between new and old generation to treat them differently. TDU Systems also notes that the Commission in *KCP&L* did not take into account the differences between firm and non-firm bulk power. NIEP and ELCON conclude that the Commission erroneously found in *KCP&L* that no wholesale seller of generation has market power in generation from new facilities. NIEP asserts that in each service area there is usually only one wholesale buyer—the utility—who also is virtually always a wholesale seller of generation. Under these circumstances, NIEP argues that there cannot be arm's-length bargaining. Environmental Action complains that the Commission's proposal to codify *KCP&L* ignores significant factors that impede entry to generation markets, such as utility resistance to purchased power, state government-created barriers to non-utility generation, pancaking of rates under the contract path approach, sunk investment, and scale economies.

Commission Conclusion

In reviewing applications to sell at market-based rates, whether from new (unbuilt) capacity or existing capacity, we require that the seller (and each of its affiliates) must not have, or must have mitigated, market power in generation and transmission and not control other barriers to entry. In order to demonstrate the requisite absence or mitigation of transmission market power, a transmission-owning public utility seeking to sell at market-based rates must have on file with the Commission an open access transmission tariff for the provision of comparable service. In addition, the Commission considers whether there is evidence of affiliate abuse or reciprocal dealing.[127]

In *KCP&L*, we stated that ''in light of industry and statutory changes which allow ease of market entry, we therefore will no longer require rate applicants to submit evidence of generation dominance in long-run bulk power markets.'' [128] We further explained that we had examined ''generation dominance in many different cases over the years'' and had ''yet to find an instance of generation dominance in long-run bulk power markets.'' [129] Commenters have criticized our findings in *KCP&L*, but no commenter has provided any evidence of generation dominance in long-run bulk power markets. Moreover, we have seen no such evidence in any of the market-based rate cases we have considered since *KCP&L*. Based on the comments received, we will codify the Commission's determination in *KCP&L* that the generation dominance standard for market-based sales from new capacity should be dropped. Because the Commission's findings in *KCP&L* applied to long-run markets, we will revise proposed § 35.27 to apply to sales from capacity for which construction has commenced on or after the effective date of this Rule.[130]

The Commission wishes to clarify that dropping the generation dominance standard for new capacity does not affect the demonstration that an applicant must make in order to qualify for market-based rates for sales from its existing generating capacity. In other words, the fact that an applicant need not demonstrate its lack of generation dominance with respect to new capacity cannot be used to ''bootstrap'' the authorization of market-based rates for its existing capacity. Moreover, our evaluation of market-based rates for existing capacity will include consideration of new capacity.

In addition, the fact that we are codifying *KCP&L* does not mean that we will ignore specific evidence presented by an intervenor that a seller requesting market-based rates for sales from new generation nevertheless possesses generation dominance. For example, if the evidence indicated that the new generator, due to its proximity to an existing transmission constraint, could significantly influence the ability to move power across the constraint, we would consider such evidence in determining whether to grant the applicant's request.[131] If such evidence is presented, the Commission will evaluate whether the evidence disproves the premise that the seller lacks generation dominance with respect to its *new capacity*.

If the applicant has existing generation, the sales from which are authorized to be made on a market basis, the Commission would consider whether the new generation (when added to the existing generation with market-based authority) results in the applicant having generation dominance. On the other hand, if the applicant has existing generation, the sales from which are subject to cost-of-service regulation, the Commission would not include this generation in its analysis of the applicant's request for market-based rates for its new generation. The question of whether or not the applicant lacks generation dominance with respect to its existing capacity is relevant only if, and when, the seller applies to the Commission for authority to make wholesale sales for its existing capacity at market-based rates.

If evidence regarding an applicant's generation dominance with respect to

[121] FERC Stats. & Regs. ¶ 32,514 at 33,050.

[122] *Id*. at 33,154.

[123] 67 FERC at 61,557.

[124] *E.g.*, Entergy, EEI, Atlantic City, Duke Centerior, Houston L&P, Montana-Dakota Utilities, Canadian Petroleum Producers, DOE, Florida Power Corp, PSNM.

[125] *E.g.*, EEI, Centerior, Houston L&P, NYSEG.

[126] *E.g.*, TDU Systems, ELCON, NRECA, Environmental Action, NIEP, APPA, Power Marketing Association, EGA.

[127] *See, e.g.*, MidAmerican Energy Company, 74 FERC ¶ 61,211 (1996).

[128] *KCP&L*, 67 FERC at 61,557. *See also* discussion in proposed rule, FERC Stats. & Regs. at 33,067–68.

[129] *Id*.

[130] The NOPR's proposed language that a public utility would not have to demonstrate a lack of market power in generation for sales from capacity first placed in service on or after the date 30 days after the final rule is published in the Federal Register does not properly reflect the finding in *KCP&L*. Because *KCP&L* addressed *new* or *unbuilt* generation, the proposed language is being revised as indicated above and as set forth in the regulatory text included with this Final Rule.

[131] *Cf.* Wisconsin Electric Power Company, et al., 74 FERC ¶ 61,069 at 61,193 (1996).

its new capacity is submitted, the applicant would be required to provide a satisfactory rebuttal.

b. Market-Based Rates for Existing Generation

In the NOPR, the Commission explained that increased competition resulting from open access transmission may reduce or even eliminate generation-related market power in the short-run market (sales from existing capacity).[132] Because market power has been the primary concern of the Commission in analyzing requests for market-based rates for such sales, we sought comments on the effect of industry-wide non-discriminatory open access on our criteria for authorizing power sales at market-based rates. The Commission also sought comments on whether the generation dominance standard should be dropped for market-based sales from existing capacity.

Comments

Many commenters support, but many also oppose, market-based rates for existing generation without a case-specific analysis of generation dominance.

Supporting Market-Based Rates for Existing Generation

Many commenters (primarily IOUs and a number of state commissions) assert that existing generators will not possess market power after implementation of non-discriminatory open access transmission and that market-based rates should be permitted generically for sales from existing generation.[133]

EEI asserts that market power concerns generally would be transitory, limited to the time needed to build new facilities. Thus, it recommends that all markets be declared competitive by a date certain and that market-based rates then be allowed, with customers permitted to file complaints. Florida Power Corp believes that existing procedures under sections 205 and 206 will adequately protect consumers. Other commenters also urge the Commission to eliminate its generation dominance standard, but assert that the Commission should allow a showing of market dominance in a complaint or show cause proceeding.[134] CT DPUC notes that the Commission should be able to rely on rules of conduct, market mechanisms, and monitoring to curb any market power that may exist.

Utilities For Improved Transition argues that if utilities cannot get market-based rates, the new players in the market will have an unfair advantage, since they do not have to carry the traditional utilities' burden of older, less efficient plants.

Entergy proposes a screening test that would permit the Commission to ''deregulate'' wholesale sales to certain short-run markets. CINergy recommends that after industry-wide open access tariffs become effective, the Commission adopt a rebuttable presumption that all markets are workably competitive; that presumption could be rebutted in a section 206 proceeding.[135]

UtiliCorp, while it believes that market power will probably be fully mitigated by open access, also argues that the Commission should examine generation dominance on a region-by-region basis.[136] Montana-Dakota Utilities argues that the Commission should allow all suppliers in a power pool or RTG to have market-based rates after a Commission finding that there is sufficient generation competition within the region.

Duke states that it would be highly inconsistent for the Commission to require open access, but not allow utilities to compete in the market. It further states that the relevant market should be determined using standard antitrust techniques; the Commission should examine the options available to customers and determine whether the utility possesses monopoly power in a relevant market.

Opposing Market-Based Rates for Existing Generation

Many commenters are concerned that even with open access tariffs certain generators will be able to exercise market dominance.[137] For example, NARUC argues that utilities retain market power through their ownership of existing generation and transmission facilities, favorable long-term contracts for fuel and other inputs, and access to superior generation sites.[138] NRECA believes that the universe of generation providers is still too narrow to assume a competitive market and that other factors, such as transmission constraints and pancaking of rates, will inhibit the development of competitive markets.[139] FTC says that, although comparable transmission access could broaden the relevant geographic market for generation, the Commission should not assume that there will be no market power. It says that the Commission must continue to evaluate each case.[140] TDU Systems argues that the Commission cannot move to market-based rates without a Congressional determination that deregulation of wholesale electric rates should be implemented. It further asserts that the Commission does not have a factual basis for a reasoned conclusion that regulated utilities do not have market dominance—full open access is only a goal at this time, and the success of open access will depend upon the transmission rate structures the Commission approves.

LEPA raises concerns that the small bulk power suppliers, QFs, co-generators, EWGs, IPPs, and marketers (who provide non-requirements power) may not be able to bring competition to the wholesale market. LEPA concludes that ''barriers will exist unless buyers have full access to requirements power itself, rather than just to the chance to acquire the individual components of requirements power.'' [141] TDU Systems raises concerns about the limited number of generation providers and the effect of possible future mergers. It also argues that pancaked rates raise the cost of transmission to third parties, thereby restricting the geographic scope of markets. As a result, TDU Systems asserts that individual generators in highly concentrated regions will still be able to exert market power. OH Com expresses concerns that restrictions on siting of generation and transmission will favor nearby generators. SC Public Service Authority argues that if the Commission allows utilities to recover stranded costs their market power will not be mitigated, since customers will

[132] FERC Stats. & Regs. ¶ 32,514 at 33,093–94.

[133] *E.g.*, EEI, CINergy, Central Illinois Public Service, Citizens Utilities, Com Ed, Ohio Edison, Allegheny, Southern, Portland, NRRI, Pennsylvania P&L, PECO, Dayton P&L, Utilities For Improved Transition, Centerior, Houston L&P, Duke, ConEd, IPALCO, Salt River, PJM, NU, NYSEG, Oklahoma G&E, PA Com, OK Com, CT DPUC, CA Com, MT Com.

[134] *E.g.*, Consumers Power, Portland, Dayton P&L, CSW.

[135] *See also* Citizens Utilities.

[136] *See also* CSW, Industrial Energy Applications, Public Service Co of CO, Coalition for Economic Competition.

[137] *E.g.*, NRECA, TDU Systems, MT Com, SMUD, NEPCO, Orange & Rockland, El Paso, American Forest & Paper, NIPSCO, AEC & SMEPA, OH Com, IL Com, IN Com, Legal Environmental Assistance, LG&E, Cajun, Industrial Energy Applications, LEPA, MA DPU, MI Com, FTC, Minnesota P&L, SC Public Service Authority, WP&L, NARUC, Canadian Petroleum Producers, DOD, CCEM, Environmental Action, American Wind, Cajun, NIEP, EGA, TAPS, ELCON, Consolidated Natural Gas.

[138] *See also* NIEP, Pacificorp, CA Energy Com.

[139] *See also* MT Com, TDU Systems, Soyland.

[140] *See also* AEC & SMEPA, NIPSCO, El Paso (discusses a particular transmission constraint that it states limits its access to suppliers).

NRECA is also concerned that mergers may create a handful of ''mega-public utilities'' that may affect a regional generation market and that the Commission should apply more traditional antitrust principles in analyzing the impacts of mergers.

[141] LEPA Initial Comments Affidavit of William G. Shepherd at 4.

have to pay exit fees to switch suppliers.[142]

CCEM notes that in Order No. 636 gas pipelines were not allowed market-based rates for merchant sales until after transmission had been completely unbundled and non-discriminatory open access had been fully implemented.

DOE and DOJ assert that open access should not be assumed to mitigate market power sufficiently to justify deregulation of existing generation—structural changes, such as control of the regional grid by an independent entity, are required. DOE requests that the Commission continue to look for affiliate abuse when reviewing market-based rates for new generation. Similarly, EPA is concerned that even with open access, individual generators may still exert market power by their domination of a particular geographic market. It is also concerned that low-cost plants that are subject to weaker environmental standards could have a market advantage. NEPOOL Review Committee requests that the Commission not approve any market prices ''where the market into which the seller proposes to sell is not effectively competitive due to the absence of regional transmission products and prices.''[143]

Commission Conclusion

While the Commission expects this Rule to facilitate the development of competitive bulk power markets, we find that there is not enough evidence on the record to make a generic determination about whether market power may exist for sales from existing generation. We continue to have concerns about how to define the relevant markets and believe that a more rigorous analysis is needed than can be achieved with the limited market data that is now available. We will continue our case-by-case approach that allows market-based rates based on an analysis of generation market power in first tier and second tier markets.[144] In particular cases, however, the effect of the mandatory open access prescribed by this Final Rule may lead to the consideration of geographic markets for the applicant's generation products that are broader in scope than the first-tier and second-tier markets currently considered.[145] By the same token, in some cases, evidence of the effects of transmission constraints may circumscribe the scope of the relevant geographic market for the applicant's generation products.

While we will continue to apply the first-tier/second-tier analysis, we will allow applicants and intervenors to challenge the presumption implicit in the Commission's practice that the relevant geographic market is bounded by the second-tier utilities. Thus, for instance, applicants may present evidence that the relevant market is in fact broader than the first or second tier. In support of such a contention, an applicant would need to show more than the existence of open access. For example, an applicant might attempt to demonstrate the lack of significant transmission constraints in the more broadly defined market and that cumulative transmission rates would not significantly affect the ability of more distant suppliers to compete in the relevant market. Similarly, an intervenor may present evidence that, due to the existence of significant transmission constraints within the first- and second-tier markets, the relevant market is in fact more limited in scope.[146]

Finally, we will maintain our current practice of allowing market-based rates for existing generation to go into effect subject to refund. To the extent that either the applicant or intervenors in individual cases offer specific evidence that the relevant geographic market ought to be defined differently than under the existing test, we will examine such arguments through formal or paper hearings.

Because our goal is to develop more competitive bulk power markets, we will continue to monitor markets to assess the competitiveness of the market in existing generation, and we will modify our market rate criteria if and when appropriate. However, any changes we might make to our analysis for authorizing market-based rates in the future will not upset transactions entered into pursuant to existing market-based rate authority. The policies we put in place today to develop a smoothly functioning transmission access regime will provide useful experience and information for assessing the effects of generation concentration.

4. Merger Policy

In the NOPR, the Commission did not address possible ramifications of the NOPR with regard to its existing merger policy.

Comments

A number of commenters suggest that the Commission should reevaluate its merger policy in light of the NOPR.[147] They further suggest a number of changes that they believe need to be made to the Commission's existing merger policy.

Most commenters raising this issue express concerns that mergers will lessen competition and hinder achievement of competitive bulk power markets.[148] For example, NRECA indicates that the Commission's merger policy is at a crossroads. It believes that it is essential for the Commission to reevaluate its merger policy in concert with the proposed rulemakings.[149] Similarly, TAPS recommends that the Commission reevaluate its merger criteria to ensure that in a more competitive era, mergers are found to be consistent with the public interest only if they are pro-competitive. Several commenters argue that the Commission should continue to conduct a case-by-case investigation of the product and geographic markets that will be affected by a proposed merger.[150]

A number of commenters also suggest certain changes that they would like to see in the Commission's merger policy.[151] APPA recommends that, at a minimum, all merger approvals considered by the Commission should be conditioned on: (1) Filing an open access transmission tariff, (2) demonstrating no market power in generation or ancillary services, and (3) granting all existing requirements customers of the merged entity the right to convert existing contracts to rights to equivalent transmission capacity. Several commenters suggest adopting the U.S. Department of Justice Merger

[142] *See also* DOD and WP&L. IL Com suggests that the Commission allow market-based rates to a utility on the condition that the utility forego stranded cost recovery.

[143] NEPOOL Review Committee Initial Comments at 28.

[144] *See, e.g.,* Southwestern Public Service Company, 72 FERC ¶ 61,208 at 61,996 (1995).

[145] The Commission's practice is to define the relevant markets as those utilities directly interconnected to the applicant (first-tier markets). For each first-tier market, we consider all utilities interconnected to the first-tier utility and all utilities interconnected to the applicant as competitors in that relevant market. Thus, the competitors include the second-tier utilities directly interconnected to the relevant market and those other first-tier utilities that can reach the market by virtue of the applicant's open access transmission tariff. *See, e.g.,* Kansas City Power & Light Company, 67 FERC ¶ 61,183 at 61,556; and Heartland Energy Services, Inc., 68 FERC ¶ 61,223 at 62,061.

[146] *See* Wisconsin Public Service Corporation, 75 FERC ¶ 61, _____, slip op. at 6–7 (1996).

[147] *E.g.,* NRECA, TAPS, Wisconsin Coalition, APPA.

[148] *E.g.,* Wisconsin, Rosebud, NRECA, IN Com, Wisconsin Coalition, NIEP, Minnesota P&L, APPA.

[149] *See also* APPA.

[150] *E.g.,* Wisconsin Coalition, MMWEC.

[151] *E.g.,* APPA, Wisconsin Coalition, Minnesota P&L, IN Com.

Guidelines in analyzing merger proposals.[152]

Environmental Action and others contend that merging utilities must be required to demonstrate real net benefits to retail and wholesale customers that could not otherwise be achieved but for the proposed merger.[153]

Commenters also argue that the Commission should use its merger conditioning authority to order divestiture of transmission and generation when required to ensure competition.[154] Environmental Action and NEPOOL Review Committee suggest conditioning merger applications on the existence of regional transmission pricing arrangements to mitigate any generation market power gained by the merging entities.

Commission Conclusion

The Commission appreciates the concerns and suggestions raised with respect to our merger policy. However, since the time the NOPR was issued (and comments received thereon), we issued a Notice of Inquiry on the Commission's merger policy in Docket No. RM96–6–000.[155] There we indicated that we will review whether our criteria and policies for evaluating mergers need to be modified in light of the changing circumstances, including this final rule, that are occurring in the electric industry. The NOI proceeding will permit us to consider comments from *all* interested participants and, at the same time, allow us to review our merger criteria and policies in light of this final rule. We are committed to reviewing our merger policy in a timely manner in the ongoing NOI proceeding.[156]

5. Contract Reform

In the NOPR, the Commission explained that it believed that it could remedy unduly discriminatory practices and achieve more competitive bulk power markets without abrogating existing wholesale power supply contracts that bundle generation and transmission services and existing wholesale transmission contracts.[157] Thus, we proposed to apply the functional unbundling requirement only to transmission services under new requirements contracts, new coordination contracts, and new transactions under existing coordination contracts. However, the Commission did invite comment on whether it would be contrary to the public interest to allow all or some of the above types of existing contracts to remain in effect.

Comments

Requirements and Transmission Contracts

Many of the commenters (including utility customers and third-party power suppliers) addressing this issue oppose abrogating existing contracts on a generic basis.[158] A number of the commenters contend that existing contracts should be retained because they are the result of mutually beneficial bargaining.[159] SMUD and TANC are concerned that existing contracts providing for transmission service that is superior to the pro forma tariffs not be abrogated.[160] Ohio Edison argues that existing contracts have contributed to the emergence of competition, meet the specific needs of the parties, have been approved by the Commission, and have not been found to be unduly discriminatory or violative of the public interest, and that their preservation is consistent with the Energy Policy Act, most notably amended section 211 of the FPA. PacifiCorp and AEP express concern that contract abrogation would create competitive instability. American Forest & Paper argues that the Commission cannot refuse to honor existing contracts if it expects a competitive bulk power market to emerge.

Numerous commenters further argue that contract abrogation requires a fact-based, contract-specific evaluation, and they oppose any generic declaration that existing contracts are contrary to the public interest.[161] Some suggest that generic contract abrogation cannot be justified under the public interest standard.[162]

Missouri Basin MPA argues that the Commission should allow abrogation of existing wholesale power and transmission arrangements if the customer can demonstrate the undue competitive disadvantage caused by the arrangement.

A few commenters support some form of generic contract abrogation.[163] CCEM asserts that existing wholesale requirements customers must be given the right to convert to transmission service under non-discriminatory open access tariffs.[164] CCEM notes that this is the same relief from undue discrimination that the Commission afforded to pipeline customers in Order Nos. 436 and 500.[165] CCEM emphasizes that here, in contrast to what occurred in the gas industry, ''[c]onversion rights should be understood as the logical *quid pro quo* for introducing extra-contractual stranded-cost recovery rights into the wholesale requirements contracts of electric utilities.'' [166] NRECA asserts that it would be unduly discriminatory to allow new transmission customers to use the open access transmission tariffs, but not allow existing customers the same access.[167]

TAPS says that if those who now have discriminatory contracts are forced to live with those contracts, a fully competitive market will be delayed considerably.[168] Moreover, TAPS argues, the Commission has a statutory duty to remedy the undue discrimination that it is only now recognizing. Even if the Commission will not abrogate these contracts across the board, TAPS asserts that we should use our section 206 authority to do so on a contract-by-contract basis.

San Francisco requests that the Commission clarify that a holder of capacity rights under an existing

[152] *E.g.,* Wisconsin Coalition.

[153] *E.g.,* TAPS, Wisconsin Coalition.

[154] *E.g.,* NIEP, Wisconsin Coalition, TAPS, Environmental Action.

[155] FERC Stats. & Regs. ¶ 35,531 (1996).

[156] Our decision to review our merger policy in a separate NOI proceeding is not intended to affect a utility's business decision of whether a merger may be in the economic interest of its ratepayers and stockholders. The NOI proceeding will not prevent us from reviewing merger applications in as timely a manner as possible.

[157] FERC Stats. & Regs. ¶ 32,514 at 33,093.

[158] *E.g.,* Dayton P&L, NSP, Montaup, Southwestern, Ohio Edison, Consumers Power, Allegheny, Public Generating Pool, NEPCO, Pennsylvania P&L, Southwest TDU Group, Arizona, DOD, El Paso, Florida Power Corp, AEC & SMEPA, Atlantic City, Texaco, Tampa, CSW, Central Illinois Public Service, CA Cogen, ConEd, GA Com, Consolidated Natural Gas, Ohio Valley, Pacific Northwest Coop, Salt River, Oglethorpe, Minnesota P&L, NYSEG, Brazos, Southern, Washington Water Power, CINergy, SoCal Edison, Hoosier EC.

[159] *E.g.,* AEC & SMEPA, Cajun, Carolina P&L, NSP, Pennsylvania P&L, UNITIL, Southwestern, CSW.

[160] *See also* Dairyland, DE Muni, Arkansas Cities, Ohio Valley.

[161] *E.g.,* AEP, Associated EC, DOD, El Paso, NEPCO, Ohio Edison, PSNM, Southwest TDU Group, Utilities For Improved Transition, NYSEG, Citizens Utilities, NM Com, EGA. *See also* NRECA, TDU Systems, Blue Ridge, CCEM, Industrial Energy Applications, APPA, Cajun, Springfield, DE Muni, Missouri Basin MPA, TANC, Wolverine Coop Members, FL Com, Citizens Utilities, Soyland (support contract abrogation on a case-by-case basis).

[162] *E.g.,* Utilities For Improved Transition, NSP, Southwestern, DE Muni.

[163] *E.g.,* NRECA, CCEM, ELCON, DE Muni, Oglethorpe. Portland maintains that it would be in the public interest to abrogate existing contracts completely, but recommends that such action be taken only on a case-by-case basis.

[164] *See also* VT DPS, NYMEX.

[165] *See also* VT DPS, Portland.

[166] CCEM Initial Comments at 26. *See also* ELCON, VT DPS, Blue Ridge, NYMEX, OK Com, Missouri Basin MPA, Texas-New Mexico, TDU Systems.

[167] *See also* TDU Systems, Texas-New Mexico, TAPS, Wisconsin Municipals.

[168] *See also* NorAm. UtiliCorp argues that existing contracts should not be allowed to extend indefinitely (as through ''evergreen'' clauses) without adopting comparability. *See also* Texaco, Wisconsin Municipals, Phelps Dodge.

contract can extend contractual rights to transmission access at least coterminous with the life of the project and under a roll-over or renewal contract on the same basis as provided in the existing contract. Anoka EC proposes that when a wholesale purchaser's contract expires, it should have a right of first refusal to contract for the transmission capacity to which it previously had a right. Knoxville urges the Commission to require renegotiation of the notice and/or term of all existing contracts for which the voluntary termination period exceeds the time frame for implementation of the final rule.

NEPCO suggests that we require existing power contracts that allow rate changes to be separated into their generation and transmission components, without otherwise disturbing their terms; this would allow comparisons between the transmission service the utility provides to its power customers and the service it offers to others.[169]

Coordination Agreements

CINergy argues that coordination agreements should not be excluded from the comparability standard and that the Commission should use its authority under section 206 to require amendments to such agreements, just as it did in Order 636 in requiring unbundling of pipeline supply contracts. CINergy suggests that public utilities should be given up to three years to file the amendments to avoid hardship on the industry and the Commission's staff. CINergy further asserts that future transactions conducted under coordination agreements should be unbundled and the transmission component subjected to the comparable transmission service requirement.

Others argue that purchases under existing coordination agreements made on behalf of retail native load should not be unbundled.[170] NY Com and IL Com recommend that proposed § 35.28(c) be modified to state that the functional unbundling requirement ''exclude(s) those wholesale purchases made by the utility to serve existing or expected native retail load.''

Utilities For Improved Transition disagrees with the idea that new transactions under existing coordination agreements should be subject to the rule.[171] It argues that the sanctity of coordination contracts should be the same as for other contracts. Coordination contracts are not simply agreements to agree in the future, according to Utilities For Improved Transition; they set forth terms and rates and merely leave the timing of transactions to be resolved in the future. Moreover, it argues that the Commission has given no reason to abandon its practice of encouraging coordination sales by allowing price flexibility.

Commission Conclusion

Requirements and Transmission Contracts

We do not believe it is appropriate to order generic abrogation of existing requirements and transmission contracts. While the Commission did generically find it appropriate to modify natural gas contracts to complete the move to a competitive commodity market in natural gas, we face a different situation here. At the time the Commission addressed this situation in the natural gas industry, it was faced with shrinking natural gas markets, statutory escalations in natural gas ceiling prices under the Natural Gas Policy Act, and increased production of gas.[172] In other words, there was a market failure in the industry that required the extraordinary measure of generically allowing all customers to break their contracts with pipelines.

In contrast, there is no such market failure in the electric industry. Although changes in the industry have been and continue to be dramatic, we do not believe they compel generic abrogation of requirements and transmission contracts.[173]

While we have concluded that current conditions in the wholesale power market do not warrant the generic modification of requirements contracts, we conclude nonetheless that the modification of certain requirements contracts on a case-by-case basis may be appropriate. We conclude further that, even if customers under such contracts are bound by so-called *Mobile-Sierra* clauses, they nonetheless ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

The Commission finds that it would be against the public interest to permit a *Mobile-Sierra* clause in an existing wholesale requirements contract to preclude the parties to such a contract from the opportunity to realize the benefits of the competitive wholesale power markets. For purposes of this finding, the Commission defines existing requirements contracts as contracts executed on or before July 11, 1994.[174] By operation of this finding, a party to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract. The party, however, still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified.

This finding complements the Commission's finding that, notwithstanding a *Mobile-Sierra* clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of this Rule.[175] The Commission's complementary *Mobile-Sierra* findings are not mutually exclusive. Any contract modification approved under this Section shall provide for the utility's recovery of any costs stranded consistent with the contract modification. The stranded costs must be prudently incurred, legitimate and verifiable, as provided in Section IV.J. Further, the Commission has concluded that if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.

The Commission believes that the most productive way to analyze contract modification issues is to consider simultaneously both the selling public utility's claims, if any, that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and the customer's claim, if any, that the contract no longer is just and reasonable and therefore ought to be modified. Thus, if the selling public utility intends to claim stranded costs, it must present that claim in any section 206 proceeding brought by the customer to shorten or terminate the contract. Similarly, if the customer intends to claim that the notice or termination provision of its existing requirements contract is unjust and unreasonable, it must present that claim in any proceeding brought by the selling public utility to seek recovery of stranded

[169] *See also* Industrial Energy Applications.

[170] *E.g.*, Con Ed, Detroit Edison, IL Com.

[171] *See also* Utility Workers Union, VEPCO.

[172] *See* Pierce, Richard J., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 9 Energy L.J. 1 (1988).

[173] In addition, we do not believe that unfavorable requirements contracts will derail the attainment of competitive wholesale power markets. Indeed, many of the commenters support this position and seek to retain their existing requirements contracts.

[174] This is consistent with the definition of existing requirements contracts we have used for purposes of stranded cost recovery.

[175] *See* Section IV.J.5.

costs. This will promote administrative efficiency and will permit the Commission to consider how the contracting parties' claims bear on one another.

The Commission does not take contract modification lightly. Whether a utility is seeking a contract amendment to permit stranded cost recovery based on expectations beyond the stated term of the contract, or a customer is seeking to shorten or eliminate the term of an existing contract, we believe that each has a heavy burden in demonstrating that the contract ought to be modified. Still, we believe that given the industry circumstances now facing us, both selling utilities and their customers ought to have an opportunity to make the case that their existing requirements contracts ought to be modified. By providing both buyers and sellers this opportunity, the Commission attempts to strike a reasonable balance of the interests of all market participants. The Commission expects that many of the arguments presented by buyers and sellers in such proceedings will be fact specific.

We note that because we are not abrogating existing requirements and transmission contracts generically and because the functional unbundling requirement of the Final Rule applies only to new wholesale services, the terms and conditions of the Final Rule pro forma tariff do not apply to service under existing requirements contracts. However, if a customer's existing bundled service (transmission and generation) contract or transmission-only contract expires, and the customer takes any new transmission service from its former supplier, the terms and conditions of the Final Rule tariff would then apply to the transmission service that the customer receives.

A further issue concerning firm contract customers is their right to transmission capacity (and the rate for such capacity) when their contracts expire by their own terms or become subject to renewal or rollover. We have concluded that *all* firm transmission customers (requirements and transmission-only), upon the expiration of their contracts or at the time their contracts become subject to renewal or rollover, should have the right to continue to take transmission service from their existing transmission provider. The limitations are that the underlying contract must have been for a term of one-year or more and the existing customer must agree to match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time, and to accept a contract term at least as long as that offered by the potential customer.[176] This means that there is no right to grandfather the historical price of the transmission service. Thus, if not enough capacity is available to meet all requests for service, the right of first refusal gives the capacity to the existing customer who had contractually been using the capacity on a long-term, firm basis, assuming that it meets the conditions set forth above. Moreover, this limited right of first refusal is not a one-time right of first refusal for contracts existing as of the date of the final rule, but is an ongoing right that may be exercised at the end of all firm contract (including all future unbundled transmission contracts) terms. A customer converting existing bundled service to the Final Rule pro forma tariff would not have a reservation priority for capacity expansions, unless the existing contract provides for future transmission to the customer that requires capacity expansion.[177]

Finally, with respect to all existing requirements contracts and tariffs that provide for bundled rates, we will require all public utilities to make informational filings setting forth the unbundled power and transmission rates reflected in those contracts and tariffs. These informational rates must be submitted to the Commission within 60 days of publication of the Final Rule in the Federal Register and must also be included as a line item on all bills submitted to wholesale customers in the third month following the effective date of this final rule. The unbundled informational rates will permit wholesale customers to compare rates in anticipation of their contracts expiring so that they can evaluate alternative contracts.

Coordination Agreements

The situation as to coordination agreements requires a slightly different approach.[178] While we also believe that as a general matter it is important not to generically abrogate any coordination agreements, this is particularly true for non-economy energy coordination agreements that may reflect complementary long-term obligations among the parties. This type of agreement presents special problems and, as discussed below, we will not generically require this type of coordination agreement to be modified.[179]

Hundreds of coordination agreements exist in the industry today. Many are open-ended agreements that permit new transactions to occur well into the future. Because these contracts may not expire of their own terms in a reasonable time, they may present a larger and more enduring obstacle to non-discriminatory open access and more competitive bulk power markets. Thus, to assure that non-discriminatory open access becomes a reality in the relatively near future, we will partially modify existing economy energy coordination agreements. We will condition future sales and purchase transactions under existing economy energy coordination agreements[180] to require that the transmission service associated with those transactions be provided pursuant to this Rule's requirements of non-discriminatory open access, no later than December 31, 1996.[181] We also will require that for new economy energy coordination agreements[182] where the transmission owner uses its transmission system to make economy energy sales or purchases, the transmission owner must take such service under its own transmission tariff as of the date trading begins under the agreement.[183]

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[176] This right of first refusal exists whether or not the customer buys power from the historical utility supplier or another power supplier. If the customer chooses a new power supplier and this substantially changes the location or direction of its power flows, the customer's right to continue taking transmission service from its existing transmission provider may be affected by transmission constraints associated with the change.

[177] The above discussion on a right of first refusal addresses firm contract customers. However, the same logic applies to retail customers.

[178] For purposes of this discussion, we define coordination agreements as all power sales agreements, except requirements service agreements. In addition, for purposes of implementing the non-discriminatory, open access requirements of the Final Rule, we are dividing bilateral coordination agreements into two general categories: (1) *Economy energy coordination agreements* are contracts and service schedules thereunder that provide for trading of electric energy on an ''if, as, and when available'' basis, but do not require either the seller or buyer to engage in a particular transaction; and (2) *non-economy energy coordination agreements* are any non-requirements service agreements, except economy energy coordination agreements.

[179] The requirements for power pools and other multilateral arrangements are discussed in detail in Section IV.F.

[180] Those executed prior to 60 days after publication of the Open Access Rule in the Federal Register.

[181] The requirement to unbundle future transactions under existing economy energy coordination agreements means that if the transmission owner uses its transmission system to make economy energy coordination sales or purchases, it must take service for these transactions under its own transmission tariff after December 31, 1996.

[182] Those executed 60 days after publication of the Open Access Rule in the Federal Register.

[183] Accordingly, transmission service needed for sales or purchases under *all* new economy energy coordination agreements will be pursuant to the Final Rule pro forma tariff.

Finally, we will treat non-economy energy coordination agreements differently. We will not require their modification. However, this does not insulate such agreements from complaints that transmission service provided under such agreements be provided pursuant to the Final Rule pro forma tariff.

With respect to coordination pricing practices, we conclude that non-discriminatory open access consistent with the requirements of this Rule is necessary if we are to allow utilities to continue to use market-driven pricing, such as split-the-savings pricing, for coordination sales. Absent such non-discriminatory open access, a utility would be able to deny access to others so as to obtain a higher price for its own power sales.

6. Flow-Based Contracting and Pricing

In the NOPR, the Commission discussed the procedures to be used in establishing Stage One rates. These Stage One rates were proposed as an administrative convenience. The proposal merely followed the long-established practice of establishing rates on the basis of contract path pricing.[184] The Commission made no determination with respect to the appropriateness of flow-based pricing or contracting for other purposes.[185]

Comments

Most of the commenters addressing this issue recommend that industry or the Commission—either in this rule or ultimately—dispense with the traditional contract path basis for pricing and contracting. Most commenters also recommend that the Commission adopt or encourage a regional approach to the solution of transmission pricing problems, though they differ markedly in how to account for flows.[186]

Transmission customers generally seek to rid themselves of ''pancaked'' transmission rates that are associated with the traditional approach to transmission pricing.[187] They propose the development of regionwide transmission rates, perhaps determined on a pool or RTG basis. Most, however, do not discuss how to account for unscheduled flows.[188]

Many transmission providers, some regulatory authorities, and some individuals strongly support flow-based pricing. Most of these commenters recognize a need for a regional approach to resolve transmission pricing concerns.[189] However, many of them also appear to accept contract pricing in the near term because of the need to implement open access quickly.[190] NERC recommends that the Commission maintain an open position on the transfer scheduling process and supports changes in the process to reflect actual power flows. EEI suggests that the Commission should be willing to deviate from a contract path approach, since competition may be accompanied by greater unscheduled flows and contract pricing is not well equipped to deal with such flows. However, EEI concludes that a single approach to pricing will not be appropriate for all systems.

Other commenters, however, do raise concerns with respect to flow-based pricing. AEC & SMEPA considers flow-based pricing to be flawed because that method makes an individual customer responsible for load flow effects caused by a third party's development of the third-party's transmission system over which the customer and its transmission provider had no control. Dayton P&L fears that competition would be lessened under flow-based pricing because utilities with large transmission systems would dominate the market.

Several commenters oppose Southern's and United Illuminating's flow-based proposals, arguing that the methodologies are based on estimates of actual flows or a set of conditions with limited applicability. Various commenters also believe that a single rate is flawed and could cause just as many problems as contract path pricing.[191]

Most commenters appear to believe that the Commission endorsed contract path pricing in the NOPR. Hogan expresses concern that many industry participants' understanding of the pro forma tariffs is based on the fiction of the contract path. The MT Dept of Environmental Quality believes that despite the Commission's pledge to consider innovative pricing proposals,[192] such proposals will receive heavy scrutiny, while conventional contract path pricing proposals will receive nearly automatic approval. Dominion is concerned that relying on the initiative of individual transmission owners to develop flow-based pricing will yield slow and patchy results.

Commission Conclusion

We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach—such as a shift to some form of flow-based pricing and contracting—could severely slow, if not derailed for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule.

While we are not requiring the use of any form of flow-based pricing, we recognize that some versions of flow-based pricing could have benefits. For example, some versions of flow-based pricing could more accurately reflect and price the actual power flows on transmission systems and thus could produce efficiency gains, better generation siting decisions, and benefits for customers and utilities alike. Other versions could more accurately assign capacity rights in accordance with a party's contribution to capacity costs.

These potential benefits, however, will not simply come about in the abstract. Flow-based pricing methodologies that will achieve the benefits sought by most of the

[184] A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path.

[185] Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the ''unscheduled flows'' that occur under a contract path regime.

[186] *E.g.*, APPA, TAPS, NY Energy Buyers, Arcadia, Brownsville, Detroit Edison Customers, AMP-Ohio, Michigan Systems.

[187] *E.g.*, AMP-Ohio, NRECA, APPA, Detroit Edison Wholesale Customers, MMWEC, Missouri Basin MPA, Air Liquide, American Wind Energy, Associated Power, CCEM.

[188] Some commenters propose the development of a regional rate on a postage stamp basis, without regard to distance travelled or the actual path of power flows. *E.g.*, Air Liquide, American National Power, CA Energy Co. Several commenters do, however, propose ways to account for unscheduled flows. *E.g.*, American Forest & Paper, DE Muni, Lower Colorado River Authority.

[189] *E.g.*, CSW, EDS Utilities, Dominion, CINergy, KS Com, CT DPUC, Com Ed, Hogan.

[190] NYMEX favors contract path pricing because of its familiarity and believes that the issue should primarily be resolved by the transmitting utilities. AEP believes that the primary responsibility lies with industry to develop alternative pricing structures.

[191] *E.g.*, NU, NEPCO, BECO, Florida Power Corp.

[192] *See* FERC Stats. & Regs. ¶ 31,005.

participants in the industry are in a development stage and require further work and refinement to address some of the difficulties associated with flow-based approaches. Concurrent work on OASIS and resolving available transmission capability issues may help resolve flow-based issues. However, as demonstrated by the paucity of possible methodologies presented in the comments, developing workable methodologies will be difficult. As we explained in our Transmission Pricing Policy Statement, we are receptive to proposals for alternative rate methodologies, such as distance-sensitive and flow-based pricing, as long as the proposals are well supported. However, we have yet to receive a formal rate application for a flow-based pricing methodology that has been tested enough that it can be required on a generic basis. Thus, we have decided to go forward to achieve open access and more competitive wholesale bulk power markets without waiting for the development of a generic flow-based pricing methodology.

We wish to emphasize further that in taking this approach we are not endorsing the traditional contract path approach as the *only* available approach. We continue to approve contract path pricing because it is the long-established pricing method that comes to us in rate filings by the electric industry, is administratively convenient and feasible, and thus is a practical way to move forward now. We remain open to alternative methodologies, but need to see better developed approaches from the industry before we can consider generic adoption of alternative pricing.

We also believe the adoption of flow-based pricing will be more practical on a regional, instead of individual utility, basis. Some forms of flow-based pricing may even require a regional approach. To this extent, regional ISOs could be a valuable mechanism for implementing such pricing reforms.

B. Legal Authority

The Commission reaffirms its conclusion in the NOPR that we have the authority under the FPA to order wholesale transmission services in interstate commerce to remedy undue discrimination by public utilities. We analyze below the relevant cases examining our wheeling authority, then discuss and respond to the legal arguments raised by the commenters.

1. Bases for Legal Authority

a. Undue Discrimination/ Anticompetitive Effects

In upholding the Commission's order requiring non-discriminatory open access in the natural gas industry, the court in *Associated Gas Distributors* v. *FERC* stated that the Natural Gas Act ''fairly bristles'' with concern for undue discrimination.[193] The same is true of the FPA. The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. As discussed below, *AGD* demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access[194] as a remedy for undue discrimination. The *AGD* court reached this decision even in the face of prior cases that acknowledged that Congress did not mandate common carriage or explicitly empower the Commission to order direct access for either gas transporters or electric utilities. Moreover, the Commission's power under the FPA ''clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to (FPA) sections 202 and 203, and under like directives contained in sections 205, 206, and 207.''[195]

Therefore, based on the mandates of sections 205 and 206 of the FPA and the case law interpreting the Commission's authority over transmission in interstate commerce, we conclude that we have ample legal authority—indeed, a responsibility—under section 206 of the FPA to order the filing of non-discriminatory open access transmission tariffs if we find such order necessary as a remedy for undue discrimination or anticompetitive effects.[196] We discuss below the primary court decisions that touch on our wheeling authority under sections 205 and 206.

The Commission's authority to order access as a remedy for undue discrimination under the Natural Gas Act (NGA) was upheld and discussed in detail in *AGD*. In *AGD*, the court upheld in relevant part the Commission's Order No. 436.[197] That order found the prevailing natural gas company practices to be ''unduly discriminatory'' within the meaning of section 5 of the NGA (the parallel to section 206 of the FPA) and held that if pipelines wanted blanket certification for their transportation services, they must commit to transport gas for others on a non-discriminatory basis; in other words, they must provide non-discriminatory open access.

In upholding the Commission's authority to require open access, the court first noted that the opponents' arguments against such authority must proceed ''uphill.'' The statute contains no language forbidding the Commission to impose common carrier status on pipelines, let alone forbidding the Commission to impose ''a specific duty that happens to be a typical or even core component of such status.'' The court found that the legislative history cited by the opponents came nowhere near overcoming this statutory silence. Rather, the legislative history supported only the proposition that Congress itself declined to impose common carrier status.[198] Emphasizing Congress' deep concern with undue discrimination, the court found that the Commission had ample authority to ''stamp out'' such discrimination:

> The issue seems to come down to this: Although Congress explicitly gave the Commission the power and the duty to achieve one of the prime goals of common carriage regulation (the eradication of undue discrimination), the Commission's attempted exercise of that power is invalid because Congress in 1906 and 1914 and 1935 and 1938 itself refrained from affixing common carrier status directly onto the pipelines and from authorizing the Commission to do so.

[193] Associated Gas Distributors v. FERC, 824 F.2d 981, 998 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) (*AGD*).

[194] We use the term ''open access'' to refer to a public utility's obligation to put a tariff on file offering service to eligible customers. Access is not open to all. Specifically, the tariff is not an offer to serve retail customers if state law does not permit retail wheeling.

[195] Gulf States Utilities Company v. FPC, 411 U.S. 747, 758–59 (1973).

[196] In most situations, discrimination that precludes transmission access or gives inferior access will have at least potential anticompetitive effects because it limits access to generation markets and thereby limits competition in generation. Similarly, it is probable that any transmission provision that has anticompetitive effects would also be found to be unduly discriminatory or preferential because the anticompetitive provision would most likely favor the transmission owner *vis-a-vis* others.

[197] Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs., Regulations Preambles ¶ 30,665 (1985).

[198] *AGD, supra*, 824 F.2d at 997.

And this proposition is said to control no matter how sound the Order may be as a response to the facts before the Commission. We think this turns statutory construction upside down, letting the failure to grant a general power prevail over the affirmative grant of a specific one.[199]

The *AGD* court found that court decisions under the FPA did not support the view that the Commission's authority to ''stamp out'' undue discrimination is hamstrung by an inability to require non-discriminatory open access as a remedy. These decisions are discussed below.

One of the earliest cases on wheeling is *Otter Tail Power Company* v. *United States (Otter Tail)*.[200] In that case, the Supreme Court rejected the argument that the District Court, in a civil antitrust suit, could not order wheeling because to do so would conflict with the FPC's purported wheeling authority.[201] The Court explained that Congress had decided not to impose a common carrier obligation on the electric power industry and noted that the Commission was not at that time expressly granted power to order wheeling.[202] In effect, it concluded that because Congress did not include common carrier provisions in the FPA, the Commission must not have any express authority to order wheeling that would preclude the District Court from imposing a wheeling remedy. Nowhere, however, did the Court say that the Commission lacked authority under section 206 to remedy undue discrimination. Indeed, that was simply not a matter before the Court or of any consequence to its decision.

In the FPA, while Congress elected not to impose common carrier status on the electric power industry, it tempered that determination by explicitly providing the Commission with the authority to eradicate undue discrimination—one of the goals of common carriage regulation.[203] By providing this broad authority to the Commission, it assured itself that in preserving ''the voluntary action of the utilities'' it was not allowing this voluntary action to be unfettered. It would be far-reaching indeed to conclude that *Otter Tail*, which was a civil antitrust suit that raised issues entirely unrelated to our authority under section 206, is an impediment to our achieving one of the primary goals of the FPA—eradicating undue discrimination in transmission in interstate commerce in the electric power industry.

In *Richmond Power & Light Company* v. *FERC* (*Richmond*),[204] the FPC, in reaction to the 1973 oil embargo, was attempting to reduce dependence on oil. The FPC requested that utilities with excess capacity wheel power to the New England Power Pool (NEPOOL). In response, several suppliers and transmission owners filed rate schedules with the FPC that provided for voluntary wheeling. Richmond Power & Light Company (Richmond) objected to these filings, claiming that they were unreasonable because they did not guarantee transmission access. The FPC refused to compel the utilities to wheel Richmond's power, stating that it did not have the authority to order a public utility to act as a common carrier.

The D.C. Circuit upheld the Commission. It acknowledged that Richmond's argument was persuasive in some respects, but stated that any conditions the Commission might impose could not contravene the FPA. The court examined the legislative history of the FPA and stated that ''[i]f Congress had intended that utilities could inadvertently bootstrap themselves into common-carrier status by filing rates for voluntary service, it would not have bothered to reject mandatory wheeling * * *.''[205]

However, the D.C. Circuit in no way indicated that the Commission was foreclosed from ordering transmission as a remedy for undue discrimination. Richmond also had argued that the alleged refusal of the American Electric Power Company (AEP) and its affiliate, Indiana & Michigan Electric Company (Indiana), to wheel Richmond's excess energy was unlawful discrimination because AEP and Indiana wheeled higher-priced electricity from other AEP affiliates. The court acknowledged that Richmond's claim of unlawful discrimination was theoretically valid, but found that Richmond had failed to prove its case. It noted that if Richmond had argued that the rates were unjustifiably discriminatory, or that Indiana's failure to use its transmission capability fully or to purchase less expensive electricity for wheeling resulted in unnecessarily high rates, a different case would be before the court.[206] The case thus does not in any way limit the Commission's authority to remedy undue discrimination.

In *Central Iowa Power Cooperative* v. *FERC*,[207] the FPC[208] reviewed the terms of the Mid-Continent Area Power Pool (MAPP) Agreement under its section 205 and 206 authority. The agreement contained two membership limitations. First, the agreement established two classes of membership, with one class being entitled to more privileges than the other. Second, the agreement excluded non-generating distribution systems from pool services. The FPC found the first limitation on membership—the two-class system—to be unduly discriminatory and not reasonably related to MAPP's objectives. The FPC conditioned approval of the agreement under section 206 on the removal of the unduly discriminatory provision. The FPC found that the second limitation, the exclusion of non-generating distribution systems, was not anticompetitive and did not render the agreement inconsistent with the public interest.

On appeal, the D.C. Circuit affirmed the FPC's decision. The court found that the FPC did have authority to order changes in the scope of the MAPP agreement, *if* the agreement was unjust, unreasonable, unduly discriminatory or preferential under section 206 of the FPA. The court stated:

The Commission had authority, * * * under section 206 of the Act, * * * to order changes in the limited scope of the Agreement, including the addition of pool services, if, in the absence of such modifications, the Agreement presented ''any rule, regulation, practice or contract (that was) unjust, unreasonable, unduly discriminatory or preferential.''[209]

However, the court agreed with the FPC's conclusion that the limited scope of MAPP was not unjust, unreasonable, or unduly discriminatory. The court recognized that a pool was not invalid under section 206 merely because a more comprehensive arrangement was possible.

The D.C. Circuit upheld the Commission's refusal to eliminate the second limitation on membership by ordering MAPP participants to wheel to non-generating electric systems.[210] However, neither the Commission nor the court was presented with the argument that wheeling was necessary as a remedy for undue discrimination.

[199] *Id.* at 998.

[200] 410 U.S. 366 (1974).

[201] 410 U.S. at 375–76.

[202] *Id.* at 374–76.

[203] *See AGD*, 824 F.2d at 998.

[204] 574 F.2d 610 (D.C. Cir. 1978).

[205] *Id.* at 620.

[206] *Id.* at 623, nn.53 and 57.

[207] 606 F.2d 1156 (D.C. Cir. 1979).

[208] While *Central Iowa* was pending, certain of the functions of the FPC were transferred to the FERC under the DOE Organization Act. Accordingly, the FERC was substituted for the FPC as the respondent in the case.

[209] 606 F.2d at 1168.

[210] *Id.* at 1169; *see also* Municipalities of Groton v. FERC, 587 F.2d 1296 (D.C. Cir. 1978).

In *Florida Power & Light Company* v. *FERC (Florida),*[211] the Commission ordered Florida Power & Light Company (FP&L) to file a tariff setting forth FP&L's policy relating to the availability of transmission service.[212] FP&L objected to including such a policy statement in its tariff and argued that the filing of such a policy would convert FP&L into a common carrier by obligating it to offer service to all customers.[213] There was no finding that the action ordered was necessary to remedy undue discrimination.

The Fifth Circuit Court of Appeals agreed with FP&L that the mandatory filing of the policy statement would require FP&L to provide transmission service beyond its voluntary commitment because such a requirement would change its duties and liabilities.[214] The Commission order would impose common carrier status on FP&L, the court found.[215] The court noted that the Commission did not rely on a finding of anticompetitive behavior and therefore the court did not address the Commission's power to remedy antitrust violations.[216]

The *AGD* court explicitly rejected the claim that the above line of cases establishes that the Commission lacks authority to require non-discriminatory open access.[217] Opponents of the Commission's order argued in *AGD* that *Richmond* and *Florida, supra,* stand for the proposition that the Commission cannot indirectly do what it allegedly cannot do directly, that is, impose common carriage. The *AGD* court rejected these arguments, stating that the petitioners read the electric cases far too broadly:

> (n)either *Richmond* nor *Florida* comes anywhere near stating that the Commission is barred from imposing an open-access condition in all circumstances.[218]

The court noted that the *Florida* case had expressly left open the question of whether the Commission would be entitled to use an open access condition as a remedy for anticompetitive conduct, and that in *Richmond* the D.C. Circuit had said little more than that unwillingness to transmit for all could not be automatically deemed undue discrimination. The court also noted the *Central Iowa* case, *supra,* in which it had upheld a Commission order that found a power pooling agreement discriminatory on its face because the agreement gave one class of membership privileged status over another. The court stated that the *Central Iowa* case ''upholds the power of the Commission to subject approval of a set of voluntary transactions to a condition that providers open up the class of permissible users.'' [219] The court added that it refused to ''turn statutory construction upside down'' by letting Congress' failure to grant a general power of common carriage prevail over the affirmative grant of the specific power to eradicate undue discrimination.[220]

We conclude that *AGD*'s analysis of undue discrimination under sections 4 and 5 of the Natural Gas Act is equally applicable to an undue discrimination analysis under sections 205 and 206 of the FPA. The Commission and courts have long recognized that the NGA was patterned after the FPA and that the two statutes should be interpreted in the same manner.[221] Thus, we conclude that we have the authority to remedy undue discrimination and anticompetitive effects by requiring all public utilities that own, control or operate transmission facilities to file non-discriminatory open access transmission tariffs.

b. Section 211 of the Federal Power Act

In concluding that we must invoke our section 206 authority to remedy undue discrimination and anticompetitive effects in the electric industry, we have carefully considered the goals of Title VII of the Energy Policy Act, and whether section 211 of the FPA, by itself, is sufficient to remedy undue discrimination in public utility transmission services. Title VII of the Energy Policy Act, which amended section 211 of the FPA to give the Commission broader authority to order wheeling in the public interest on a case-by-case basis, reflects the intent of Congress to encourage competitive wholesale electric markets. Section 211 provides a means for wholesale power sellers and buyers to obtain transmission services necessary to compete in, or to reach, competitive markets, and is a valuable tool to encourage competitive markets. However, in amending section 211, Congress left unaltered the authorities and obligations of the Commission under sections 205 and 206 (similar to our authorities and obligations under sections 4 and 5 of the NGA) to remedy undue discrimination. In addition, as discussed below, reliance on section 211 alone in some circumstances can result in the perpetuation of, rather than the elimination of, undue discrimination and anticompetitive effects.

First, there are inherent delays in the procedures for obtaining service under section 211. However, for competitive reasons, many transactions must be negotiated relatively quickly. Many competitive opportunities will be lost by the time the Commission can issue a final order under section 211. Case-by-case section 211 proceedings are not a substitute for tariffs of general applicability that permit timely, non-discriminatory access on request.

Second, discrimination is inherent in the current industry environment in which some customers and sellers are served by open access systems, and others have to rely on negotiated bilateral arrangements or the mandatory section 211 process. The end result is discrimination in the ability to obtain transmission services, as well as in the quality and prices of the services. This national patchwork of open and closed transmission systems, with disparate terms and conditions of service, cannot be cured effectively through section 211.

The Commission believes that its actions under sections 205 and 206 will complement the section 211 procedures

[211] 660 F.2d 668 (5th Cir. 1981), *cert. denied sub nom.* Fort Pierce Utilities Authority v. FERC, 459 U.S. 1156 (1983).

[212] FP&L provided transmission service when four conditions were met: (1) The specific potential seller and buyer were contractually identified; (2) the magnitude, time and duration of the transaction were specified prior to the commencement of the transmission; (3) it could be determined that the transmission capacity would be available for the term of the contract; and (4) the rate was sufficient to cover FP&L's costs.

[213] All utilities requesting wheeling services, subject to availability, would be entitled to receive transmission service under the filed terms. Any changes to a filed rate must be filed with the Commission. This is the so-called ''filed rate doctrine.'' *See* Northwestern Public Service Company v. Montana-Dakota Utilities Company, 181 F.2d 19, 22 (8th Cir. 1980), *aff'd,* 341 U.S. 246 (1951).

[214] Under the filed rate doctrine, a refusal to wheel would be unduly discriminatory under section 206 of the FPA. As the court acknowledged, a customer refused service could petition the Commission to find that FP&L's policy of availability was unduly discriminatory under section 206(a) of the FPA. The court said that in the absence of a tariff on file, a utility refused wheeling services would be unable to claim discrimination under section 206(a) of the FPA. 660 F.2d at 675 (expressing ''serious doubts that such a petition would be successful in the absence of a tariff'').

[215] *Id.* at 676.

[216] *Id.* at 678.

[217] The *AGD* court did not address New York State Electric & Gas Corporation v. FERC, 638 F.2d 388 (2d Cir. 1980), *cert. denied,* 454 U.S. 821 (1981) *(NYSEG),* presumably because that case did not concern whether the Commission could order wheeling as a remedy for undue discrimination.

[218] 824 F.2d at 999.

[219] *Id.* at 999.

[220] *Id.* at 1006.

[221] *See, e.g.,* FPC v. Sierra Pacific Power Company, 350 U.S. 348, 353 (1956); Arkansas Louisiana Gas Company v. Hall, 453 U.S. 571, 577 n.7 (1981); and Kentucky Utilities Company v. FERC, 760 F.2d 1321, 1325 n.6 (D.C. Cir. 1985). Section 206 of the FPA was recently revised and now differs from section 5 of the NGA, but not in a manner significant to our discussion here. *See* 16 U.S.C. 824e (b) and (c).

to achieve both the Energy Policy Act's goals of creating more competitive bulk power markets and lower rates for consumers and the Federal Power Act's explicit direction in section 205(b) that no public utility shall, with respect to any transmission in interstate commerce, grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage.

2. Response to Commenters Opposing Our Legal Authority

a. Authority to Order Open Access Tariffs

Comments

Initial Comments Supporting Commission Authority

A number of commenters support or state that they do not oppose the Commission's authority to order open access tariffs.[222] NIEP and CCEM explain that the *AGD* decision supports the Commission's action in this proceeding. ELCON asserts that the Commission's ''extensive treatment of the relevant case law demonstrating FERC's authority to remedy this discrimination is legally sound.'' UtiliCorp argues that section 211 supports, rather than undermines, the Commission's authority for the NOPR because it reflects Congress's intention to encourage more competitive bulk power markets.

Initial Comments Opposing Commission Authority

Other commenters assert that the Commission has improperly relied on sections 205 and 206 of the FPA to require open access.[223] They argue, for instance, that *Otter Tail* should be read as a broad constraint on the Commission's authority to order wheeling for *any* purpose and that the *AGD* decision does not undermine that holding or the cases following *Otter Tail*.[224] In support, some of these commenters discuss *Richmond Power & Light, New York State Electric & Gas Corporation,* and *Florida Power & Light Company,* the same cases discussed by the Commission in the NOPR.[225]

For example, EEI highlights the *AGD* court's discussion noting the difference between the legislative history of the NGA and that of the FPA, which the court stated was not as strong as that of the NGA. Moreover, EEI argues that the court found that section 7 of the NGA provided support for the Commission's actions in Order No. 436 and that such section 7 conditioning authority is lacking under the FPA. Allegheny notes that *AGD* did not overrule *Otter Tail.* Dayton P&L states that, in the gas case, the Commission was responding to voluntary filings by pipelines. It also says that before the NOPR, the Commission itself saw its authority as more limited. SCE&G points to differences between Commission jurisdiction over public utilities and gas pipelines and criticizes the Commission's alleged assumption that the circumstances involved in the gas and electric industries are virtually identical.

PA Com argues that the attempt to analogize to the NGA and the cases that refer to that Act is inconsistent with the technical and engineering realities of the electric transmission grid and that extensive comparisons between the natural gas industry and the electric industry are misleading.[226]

FL Com argues that, in relying on sections 205 and 206 to establish generic open access transmission tariffs for *all* public utilities, the Commission violates the court's decision in *Cajun Electric Power Cooperative* v. *FERC,* 28 F.3d 173 at 179 (D.C. Cir. 1994), where, FL Com argues, the court refused to allow the Commission to use a non-evidentiary ruling when there were material facts at issue.

Reply Comments

CCEM responds that EEI and others confuse the obligations of a common carrier with the duty of public utilities not to unduly discriminate. It says that *AGD* supports the Commission's authority because the legislative history of the FPA and the NGA are similar with respect to common carriage. According to CCEM, early versions of both statutes would have made the regulated industries operate as common carriers (citing *Otter Tail,* the legislative history of the FPA, the legislative history of the Public Utility Holding Company Act, and the legislative history of the Mineral Leasing Act), but that Congress chose not to impose the common carrier obligations.

CCEM also says that the duties the Commission imposed on the gas industry and those in the NOPR are not common carriage in any event. According to CCEM, a common carrier must carry all goods offered (citing *Am. Trucking Assoc.* v. *Atchison, T. & S.F. Ry. Co.,* 387 U.S. 397, 406 (1967)). Finally, CCEM cites *Stephenson* v. *Binford,* 287 U.S. 251, 265–66 (1932), where the Supreme Court held that obligations that are typical of common carriers can be imposed on contract motor carriers.

CCEM further disagrees with EEI's argument that the enactment of section 211 was a disavowal of any other Commission authority to order transmission.

ELCON also disagrees with EEI's claim that the Energy Policy Act undermines the Commission's pre-existing section 205 and 206 authority. It states that the savings clause in section 212(e) of the FPA, as amended, explicitly expresses Congress' intention not to undermine the Commission's pre-existing authority and that the legislative history contains nothing to suggest otherwise.

Similarly, in response to those who argue that section 211 is the only source of authority for the Commission to order transmission, NIEP argues that sections 211 and 212 serve purposes different from section 206. It says that the Commission's authority to order transmission in the ''public interest'' under sections 211 and 212 is not synonymous with its authority to order transmission as a remedy for undue discrimination under section 206; the two standards are complementary but distinct:

> Although broadly applicable, the Commission's ability to order wheeling under sections 211 and 212 is carefully limited by a number of procedural provisions. Foremost among these is the requirement that the wheeling may be ordered only upon a specific application for transmission services. FERC's authority to act in the public interest is thus confined to the individual case.
>
> By contrast, FERC's remedial powers under Section 206 can be exercised upon a finding of unjust, unreasonable or unduly discriminatory or preferential practices. Once that finding has been made, however, the form and substance of the remedy is left entirely to the FERC's discretion. If FERC deems it necessary, FERC may adopt generally applicable rules or practices as a countermeasure to discriminatory acts, including ordering utilities to file generally applicable transmission tariffs.[227]

NIEP also points out that the legislative history does not address the Commission's authority to order transmission as a remedy for undue discrimination. It challenges the

[222] NIEP, ELCON, CINergy, UtiliCorp, TAPS, SBA, Entergy, NY Energy Buyers, Sierra.

[223] *E.g.,* EEI, Atlantic City, Allegheny, VA Com, PA Com, Ohio Edison, Southern, Utilities For Improved Transition, Dayton P&L, SCE&G, Centerior, BG&E, Central Hudson, NY Com, Salt River, Carolina P&L, Union Electric, VEPCO, Utility Workers Union.

[224] EEI, VA Com, Union Electric.

[225] *E.g.,* EEI, VA Com, NY Com, PA Com, Salt River, Southern, Dayton P&L, Detroit Edison, BG&E.

[226] *See also* NY Com (NGA has no parallel provision to section 211 of the FPA), Salt River.

[227] NIEP Reply Comments at 8.

interpretation of the legislative history advanced by some commenters.[228]

Next, NIEP defends the Commission's proposed findings that there is generally undue discrimination in the provision of transmission service. It notes that when an agency acts on an industry-wide basis, the agency does not have to make a finding as to each particular case.

Finally, NIEP responds to those who argue that *AGD* is not on point. It notes that the *AGD* court discussed electric cases and emphasizes the court's statement that the NGA ''fairly bristles with concern for undue discrimination''—a statement that is equally true of the FPA.

TDU Systems responds to the argument that *Otter Tail* is a broad constraint on the Commission's authority to order transmission.[229] At issue in that case, it argues, was the reach of the Sherman Act, not of FPA sections 205 and 206. Similarly, it argues, the *Florida Power* case is not on point, and the court there specifically said that it was not deciding whether the Commission could have ordered wheeling as a remedy for anticompetitive activities. Moreover, TDU Systems asserts that EEI's use of a quote from a single Senator should carry no weight, since it is a well-established principle of statutory construction that such statements have little value. Finally, it points out that the *AGD* court itself did not view *Otter Tail* or other electric precedent as forbidding the Commission to order wheeling as a remedy for undue discrimination.

Entergy asserts that Congress's refusal to require utilities to provide transmission as common carriers or whenever it is in the public interest was merely a decision not to give the Commission general authority to order wheeling, without regard to undue discrimination. Thus, the *Otter Tail* language concerning the absence of a common carrier requirement does not demonstrate that Congress meant to limit the Commission's authority to remedy undue discrimination.

ELCON disputes EEI's reading of *NYSEG*, noting that the *NYSEG* court explicitly stated:

> Nor do we suggest that the Commission is powerless to review a wheeling agreement under section 206 without following the requirements of sections 211 and 212.[230])

TAPS discusses numerous cases, including the primary cases relied upon by the Commission, and disposes of *NYSEG* by stating that it is no longer good law, if it ever was.

Commission Conclusion

There can be no question that the Commission has the authority to remedy undue discrimination. Sections 205 and 206 of the FPA mandate that we ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. Under these sections, we must determine whether *any* rule, regulation, practice, or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and we must disapprove those contracts and practices that do not meet this standard. Our discretion is at its zenith in fashioning remedies for undue discrimination.[231]

Some commenters, however, challenge our authority to order industry-wide non-discriminatory open access as a remedy for the undue discrimination we have found in the industry. As summarized above, they essentially assert that we are prohibited by court precedent, the legislative history of the FPA, and sections 211 and 212 of the FPA from ordering wheeling as a remedy for undue discrimination. We disagree and conclude that we have the authority—indeed, a responsibility—to require non-discriminatory open access transmission as a remedy for undue discrimination.

AGD and Legislative History

The court decision in *Associated Gas Distributors* v. *FERC* provides powerful support for our ability to order industry-wide non-discriminatory open access transmission in the electric industry as a remedy for undue discrimination. As discussed in detail above, *AGD*, which is the only decision to have addressed the Commission's authority to remedy undue discrimination by requiring open access, upheld our authority under section 5 of the NGA (the parallel to section 206 of the FPA) to require open access in the natural gas industry. The rationale supplied by the *AGD* court applies equally to the FPA and our responsibility to eliminate undue discrimination in the electric industry.

Those who challenge the Commission's legal authority to remedy undue discrimination face the same difficulty that parties faced in seeking to overturn open access in the natural gas industry—they ''can point to no language in the (FPA) barring the Commission from imposing common carrier status on (public utilities), and certainly none barring it from imposing upon the (public utilities) a specific duty that happens to be a typical or even core component of such status.'' [232] Instead, as was unsuccessfully attempted in the *AGD* proceeding, they seek to overcome the statutory silence primarily by means of legislative history. However, as the *AGD* court explained, legislative history is not even relevant, because

> courts have no authority to enforce principles gleaned solely from legislative history that has no statutory reference point.[233]

Here, as the court found with respect to the NGA, the legislative history of the FPA ''provides strong support only for the point that Congress declined *itself* to impose *common carrier status* on (public utilities) * * * It affords weak—almost invisible—support for the idea that the Commission could under no circumstances whatsoever impose obligations encompassing the core of a common carriage duty.'' [234]

Commenters focus on the following statement in the *AGD* decision to support the argument that, because Congress did not expressly reject common carriage under the NGA, but did reject it under the FPA, a different outcome in this proceeding is required:

> we note that the legislative history of the two acts is, on this point, materially different. In its deliberations on the bill that ultimately emerged as the Federal Power Act, Congress considered and rejected a provision that would have ''empowered the Federal Power Commission to order wheeling if it found such action to be 'necessary or desirable in the public interest.' '' (citing *Otter Tail*) (quoting S. 1725, 74th Cong., 1st Sess.). The evidence as to the NGA (surveyed above) is less direct: it consists exclusively of various occasions on which Congress did not adopt proposals actually making the natural gas pipelines into common carriers.[235]

[228] NIEP explains that

> (W)hile much has been made of the Senate report accompanying S.2114, which subsequently became part of PURPA in 1978, that report does not illustrate an intent to limit FERC's authority to remedy undue discrimination under section 206. That report characterizes the Supreme Court's decision in *Otter Tail* as holding that ''the Federal Power Act leaves open a gap in its failure to assign the FPC general authority to order wheeling *in this situation* * * *.'' The ''situation'' to which the Report refers is not discrimination, however. Instead, the statement appears to make reference to circumstances in which general public interest concerns, such as reliability, efficiency and competition, are at stake. Thus, Senate Report 2114 is simply not a limitation on the Commission's remedial powers under Sections 206.

NIEP Reply Comments at 8–9 (citations omitted).

[229] See also Entergy.

[230] ELCON Initial Comments at 7 (quoting *NYSEG* at 403).

[231] *See, e.g.,*- Niagara Mohawk Power Corporation v. *FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967).

[232] *AGD*, 824 F.2d at 997.

[233] *Id.* (quoting *IBEW, Local No. 474* v. *NLRB*, 814 F.2d 697, 712 (D.C. Cir. 1987) (emphasis deleted by court from original)).

[234] *Id.* (emphasis added).

[235] *Id.* at 998–99.

The above statement, however, does not preclude the *AGD* court's decision on our broad authority to remedy undue discrimination in the gas industry from applying equally in the electric industry. Clearly, the court did not say that. As discussed below, we believe the statement focuses on a distinction in the legislative histories that is not meaningful.

First, whether or not a material difference exists in the respective legislative histories of the NGA and FPA, the fact remains that the crucial findings of the *AGD* court were that: (1) ''Congress declined *itself* to impose *common carrier* status'' (emphasis added) and (2) there is no ''support for the idea that the Commission could under no circumstances whatsoever impose obligations encompassing the core of a common carriage duty.'' [236] These findings apply equally to the FPA. Simply stated, statutory silence cannot be overcome by means of legislative history—even if the legislative history in fact indicated that Congress ''rejected'' legislative imposition of common carrier status under the FPA, but ''did not adopt'' it under the NGA. In either event, nothing in the statute or legislative history suggests that Congress concluded that the Commission could under no circumstances impose open access as a remedy to undue discrimination.

Moreover, the legislative history of the bills containing the FPA and the NGA, taken as a whole, suggests that the distinction drawn in *AGD* between the legislative histories of the NGA and the FPA is not meaningful. The legislation that was to become the FPA originally included provisions regulating both electric power and natural gas. As originally proposed, the legislation contained *identical* common carriage language for both public utilities and natural gas pipelines.

With respect to the FPA, the Supreme Court explained in *Otter Tail* that

(a)s originally conceived, Part II would have included a ''common carrier'' provision making it ''the duty of every public utility to * * * transmit energy for any person upon reasonable request * * *.'' In addition, it would have empowered the Federal Power Commission to order wheeling if it found such action to be ''necessary or desirable in the public interest.'' H.R. 5423, 74th Cong., 1st Sess.; S. 1725, 74th Cong. 1st Sess. These provisions were eliminated to preserve ''the voluntary action of the utilities.'' S.Rep. No. 621, 74th Cong., 1st Sess., 19.[237]

The language paraphrased by the Supreme Court was from Title II of the initial bill proposing the Public Utility Holding Company Act. The entire sections from which the paraphrased language came are as follows:

SEC. 202. (a) It shall be *the duty of every public utility to* furnish energy to, exchange energy with, and *transmit energy for any person upon reasonable request* therefor; and to furnish and maintain such services and facilities as shall promote the safety, comfort, and convenience of all its customers, employees, and the public, and shall be in all respects adequate, efficient, and reasonable.

* * *

SEC. 203. (b) Whenever the Commission after notice and opportunity for hearing finds such action *necessary or desirable in the public interest,* it may by order direct a public utility to make additions, extensions, repairs, or improvements to or changes in its facilities, to establish physical connection with the facilities of one or more other persons, to permit the use of its facilities by one or more other persons, or to utilize the facilities of, sell energy to, purchase energy from, transmit energy for, or exchange energy with, one or more other persons. Where any such order affects two or more persons, the Commission may prescribe the terms and conditions of the arrangement to be made between such persons, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them.[238]

This initial bill proposing the Public Utility Holding Company Act also included a Title III that was intended to regulate the transmission and sale of natural gas. Sections 303(a) and 304 of Title III included the *identical* common carrier language paraphrased by the Supreme Court and included in sections 202(a) and 203(b) of Title II.[239] After further deliberations, Congress rejected the above-quoted language in Title II and eventually adopted a Title II that did not include any common carrier language. On the other hand, Title III (addressing regulation of natural gas) was not reported out of committee, but reemerged in the next year.[240] The bill that reemerged did not contain the common carrier language that was in the original Title III. However, as Congress had just debated the common carrier issue in enacting electric power regulation, it is not surprising that Congress did not engage in debating the very same issue in enacting natural gas regulation.

Because of the timing of the legislation involving the FPA and the NGA and the logical nexus between the two acts, we conclude that there is in fact no material difference as to this issue in the legislative histories of the two acts. Both initially included identical common carrier language, and the language was removed from both. As to both acts, Congress chose not to impose common carrier obligations on the electric or natural gas industries, but gave the Commission the authority and responsibility to eliminate undue discrimination in both industries. Consequently, as open access was found to be a proper remedy for undue discrimination in the natural gas industry, it is also a proper remedy for undue discrimination in the electric industry.

As the *AGD* court noted with respect to the Commission's powers and duties under the NGA, Congress explicitly gave the Commission the authority to eradicate undue discrimination under the FPA. That explicit power and duty provided by Congress cannot be invalidated solely on the ground that Congress chose not to impose statutory common carrier status on public utilities or did not explicitly authorize the Commission to do so.[241] As the *AGD* court explained, this would ''turn [] statutory construction upside down, letting the failure to grant a general power prevail over the affirmative grant of a specific one.'' [242]

Other Case Law

A number of commenters argue that the Commission misinterpreted the other cases discussed in the NOPR with respect to our authority to order non-discriminatory open access transmission. We disagree. As demonstrated above, not one of the cases put forth by commenters holds that we cannot remedy undue discrimination by requiring public

[236] *Id.* at 997. We also note that the contract carriage obligation we are imposing is easily distinguished from the common carrier obligation Congress chose not to adopt. As discussed *infra,* the common carrier provisions rejected by Congress would have required transmission for ''any person'' upon reasonable request. This would have included retail purchasers.

[237] *Otter Tail,* 410 U.S. at 374.

[238] H.R. 5423, 74th Cong., 1st Sess., 32 (emphasis added).

[239] *Id.* at 44.

[240] In the debate on the subsequent bill to regulate natural gas, Congressman Cole explained:

Mr. Chairman, the House should realize that the measure we are dealing with today is of extreme importance, more so than the attendance and the time taken in the discussion would seem to indicate. It is the culmination of one of the most far-reaching, intensive studies of the Federal Trade Commission I assume that that Commission ever conducted, and last year found a place in not identical language but very similar in the Rayburn bill, the famous holding-company bill, as part 3 thereof. Our committee eliminated part 3, as members will recall, and saved it for a separate measure reported out as it was last year, which was not considered by the House, but is here today in improved form.

81 Cong. Rec. H6724 (daily ed. July 1, 1937).

[241] *AGD,* 824 F.2d at 998.

[242] *Id.*

utilities to provide non-discriminatory open access transmission.[243]

AGD is the *only* case in which a court specifically addressed our authority to order open access transmission as a remedy for undue discrimination. Its favorable finding with respect to our action under section 5 of the NGA directly supports our ordering non-discriminatory open access transmission under section 206 of the FPA.

Authority to Act by Rule

We disagree with those commenters that assert that we may find and remedy undue discrimination only through case-by-case adjudications and are prohibited from making a generic determination of undue discrimination through a rulemaking. First, there is no question that it is within our discretion whether we act through rule or through case-by-case adjudications.[244] The *AGD* court specifically rejected a similar argument that the Commission erred in requiring open access transportation tariffs without first finding that each individual pipeline's rates were unlawful. The *AGD* court held that ''(t)he Commission is not required to make individual findings if it exercises its § 5 authority by means of a generic rule.'' [245]

We have identified a fundamental generic problem in the electric industry: owners, controllers and operators of monopoly transmission facilities that also own power generation facilities have the incentive to engage, and have engaged, in unduly discriminatory practices in the provision of transmission services by denying to third parties transmission services that are comparable to the transmission services that they are providing, or are capable of providing, for their own power sales and purchases. These practices drive up the price of electricity and hurt consumers. Furthermore, the incentive to engage in such practices is increasing significantly as competitive pressures grow in the industry. It is within our discretion to conclude that a generic rulemaking, not case-by-case adjudications, is the most efficient approach to take to resolve the industry-wide problem facing us.

b. Undue Discrimination/ Anticompetitive Effects

Initial Comments

A number of commenters allege that the Commission has failed to meet its burden of proving industry-wide discrimination.[246] They assert that the Commission has provided only a few unsubstantiated allegations of discrimination, which do not represent the current conditions in the electric industry, or that the Commission has not shown that all electric utilities have unduly discriminated. Some attack the NOPR's incorporation by reference of the unsubstantiated allegations of discrimination set forth in a petition for rulemaking filed on February 16, 1995 by the Coalition for a Competitive Electric Market (CCEM).[247]

EEI argues that the allegations of discrimination in the NOPR must be considered in light of the fact that: (1) All tariffs currently on file have been found by the Commission not to be discriminatory; (2) more than 30 utilities have voluntarily filed open access tariffs, which belies any assertion of widespread discrimination in the industry; and (3) transmission disputes are rare, with only 19 section 211 proceedings having been filed in the last three years.[248] EEI concludes that the Commission's allegations of discrimination do not rise to the level of ''extreme circumstances'' found by the court in the natural gas industry in *AGD*.

EEI adds that the Commission's proposal to act under section 206 is itself discriminatory because it applies only to public utilities and does not reach all transmission-owning utilities.[249] If reciprocity is designed to resolve this problem, EEI believes that reciprocity should also be ''effective for public utilities.'' Furthermore, EEI argues that the failure of a public utility to provide to others a service that it does not provide itself is not evidence of discrimination, and that inclusion of such a provision actually results in preferential treatment for transmission users.

NE Public Power District alleges that the NOPR does not contain a single reference to any actual discrimination or anticompetitive conduct by any publicly owned utility.

Salt River asserts that the Commission is required to consider all elements of an antitrust analysis before reaching a conclusion that market power exists in the transmission system and that we have failed to do so.[250] It concludes that the NOPR ''constitutes an attempt to legislate a remedy for an evil that has not been, and cannot be, lawfully found to exist on a wholesale basis among utilities that own and operate integrated generation and transmission systems.'' [251]

PA Com argues that the Commission's request for examples of discriminatory behavior is a ''tacit admission as to the paucity of evidence of discriminatory practices by transmission owning utilities.'' NY Com argues that the ''Commission's lack of a record basis for its proposed findings is legally suspect because courts in two cases have held that the Commission cannot proceed with open access transmission tariffs absent record findings of specific anticompetitive conduct.'' [252]

Finally, EEI claims that even if the Commission has proven its allegations of discrimination, we have failed to meet the requirements of section 206 of the FPA.[253] According to EEI, the Commission cannot find, without an adjudicatory hearing, that the rates on file are unlawful and order replacement rates.[254] The Commission's proposed procedure would unlawfully place the burden of justifying existing rates on the utilities.

Reply Comments

A number of commenters provide instances of discriminatory behavior they have faced over the years. NCMPA describes difficulties it has faced in dealing with CP&L, including a situation where CP&L allegedly impeded NCMPA's use of transmission access through CP&L's control of dispatching.[255]

AMP-Ohio alleges that Toledo Edison refused to transmit emergency power on a buy-sell basis to certain AMP-Ohio members even though Toledo Edison's system was not constrained. Instead, AMP-Ohio alleges, Toledo Edison bought the power and resold it to AMP-Ohio at a higher rate.

[243] *See* FERC Stats. & Regs. at 33,053–56. We further note that the *AGD* court did not discuss the *NYSEG* decision at all. Indeed, the *NYSEG* case did not involve any allegations of undue discrimination and any discussion of section 206 by the court was dictum.

[244] *See, e.g.*, NLRB v. Bell Aerospace Company, 416 U.S. 267, 293 (1974) (citing SEC v. Chenery Corporation, 332 U.S. 194, 202–03 (1947). *See also* Heckler v. Campbell, 461 U.S. 458, 467 (1983) (even where enabling statute requires a hearing to be held, agency may rely on its rulemaking authority); Panhandle Eastern Pipeline Company v. FERC, 907 F.2d 185, 187–88 (D.C. Cir. 1990). Under section 403 of the DOE Act, 42 U.S.C. 7173, the Commission is authorized at its discretion to initiate rulemaking proceedings.

[245] *AGD*, 824 F.2d at 1008.

[246] *E.g.*, EEI, Ohio Edison, PA Com, BG&E, NY Com, Minnesota P&L, Carolina P&L.

[247] *E.g.*, EEI, BG&E.

[248] *See also* Ohio Edison.

[249] *See also* SCE&G.

[250] Salt River Initial Comments at 5–6 (referencing an attached legal memorandum of Donald A. Kaplan).

[251] Salt River Initial Comments at 6.

[252] NY Com Initial Comments at 16–18 (discussing *FPL* and *Cajun*).

[253] *See also* Southern.

[254] *See also* Southern.

[255] We note that CP&L raised legal objections to our authority to implement this rule.

APPA challenges EEI's claim that there is no substantial evidence of undue discrimination in transmission. It suggests that nineteen instances of transmission disputes being filed since the Energy Policy Act was enacted is ample evidence of undue discrimination. Moreover, according to APPA, reported abuses are only the tip of the iceberg.

CCEM responds to the argument raised by EEI and others that there is no showing of extreme circumstances of discrimination in the electric industry such as the *AGD* court noted in the gas industry. It says that these circumstances are present and gives numerous examples; it does not identify the specific utilities because ''it is the experience of * * * (our) members that nearly all transmission owners retaliate * * *'' against anyone who complains. Moreover, in answer to EEI's statement that transmission disputes are rare, CCEM states that since most of the competition is in the short-term market, it has not been worthwhile to file complaints. The examples provided by CCEM include: (1) Refusal by a California public utility to offer firm service; (2) refusal by control area utilities in Texas to offer ancillary services to a power marketer, with the result that one of the utilities won the bid, even though it did not have the lowest price; (3) non-utilities in ERCOT being unable to compete to meet short-term requests for economy energy because they were required to schedule by noon of the preceding day, while utilities did not subject themselves to such a scheduling requirement; (4) power pool or control area information requirements, particularly in the northwest part of WSPP, that force non-utilities to reveal commercially sensitive information; the transportation operator has then revealed the information to its own or its affiliate's sales arm, which ''steals'' the deal; (5) a northeast power pool that refused to wheel out even though capacity was available on the grounds that sending power out of the pool would drive up prices in the pool (hoarding); (6) a power marketer that asked a utility to provide transmission, whereupon the utility bought up certain transmission capacity necessary for the marketer to reach its buyer, thus blocking the path—this was possible because the utility was able to locate the purchaser based on commercially sensitive information the marketer had to give the utility when the marketer asked for transmission; (7) a common contracting practice among utilities restricting the use of interconnections to themselves, particularly in the Southwest Power Pool, MAPP, and MAIN; (8) utilities overstating the cost of improvements (gold-plating) and thus discouraging service. CCEM also responds to each of EEI's criticisms of CCEM's examples of undue discrimination submitted in its February 16, 1995 petition and argues that its examples of undue discrimination are unrebutted.

Brownsville asserts that

> while PUB [Brownsville] must pay multiple distance-based and pancaked transmission rates to engage in transactions with the non-ERCOT universe, El Paso Electric would have *received* transmission payments from its merger partners while gaining *free* transmission access to buy and sell within ERCOT. CSW presently walls other ERCOT utilities off from participation in the Western Systems Power Pool, while its ERCOT subsidiaries, CPL and WTU, share in the benefits of their non-ERCOT affiliates' WSPP memberships via the preferential terms of the CSW Operating Agreement. CSW treats its own inter-affiliate central dispatch as having a higher priority than third-party economy energy transactions, with the result that CPL not infrequently crowds PUB out of the economy market. [256]

Wisconsin Municipals states that its members have been fighting transmission battles for years and sets forth five examples of the sort of difficulties it has experienced in attempting to obtain transmission rights. For example, it explains that Wisconsin public utilities have resisted an effort by the state commission to achieve comparability of use of transmission. Wisconsin Municipals also explains a situation where ''if WPPI continued to purchase its power from WPSC, it would pay WPSC $843,840 annually for transmission service: if it purchases power off system from WP&L (one of WPSC's competitors), WPPI would pay WPSC $1,774,224 for transmission service to the exact same load.''

TAPS sets forth additional examples of undue discrimination, including refusals to wheel even in the face of Nuclear Regulatory Commission (NRC) nuclear license conditions requiring wheeling, and Northeast Utilities' refusal to provide transmission to a QF even though it had indicated to the Commission that it would provide such transmission in order to obtain Commission approval of its proposed merger with Public Service Company of New Hampshire.

NIEP sets forth ten examples of undue discrimination that its members have experienced in seeking access to transmission service at reasonable terms and conditions.

Some commenters challenge these claims of undue discrimination. For example, Carolina P&L responds to NCMPA #1's example of obstruction by Duke in accommodating energy sales from the jointly owned Catawba Plant. Carolina P&L explains that NCMPA #1's proposal ''would require Duke to provide its own generation resources on behalf of NCMPA #1 in order to support a bulk power sale when NCMPA #1's own resource capacity and energy are not sufficient for the sale.'' Carolina P&L argues that this is backstanding that goes beyond the scope of any ancillary service the Commission has proposed and would be entirely inappropriate ''to compel the Transmission Provider to sell power to its Transmission Customer for resale on the bulk power market.''

Duke also responds to NCMPA #1's claim of discrimination and asserts that NCMPA #1's claim is not relevant to the NOPR proceeding, but is a specific contractual claim that should be pursued pursuant to the terms of its contract.

Commission Conclusion

We conclude that unduly discriminatory and anticompetitive practices exist today in the electric industry and, more importantly, that such practices will increase as competitive pressures continue to grow in the industry, unless the Commission acts now to prevent such practices.[257] It is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves. The inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation, and it is our duty to eradicate unduly discriminatory practices. As the *AGD* court stated: ''Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [258]

We set forth examples in the NOPR of undue discrimination that we believe are occurring in the electric industry and invited commenters to identify any discrimination that they may have experienced. In response, commenters

[256] Brownsville Reply Comments at 2–3 (emphasis in original).

[257] While many public utilities have filed some form of open access tariff (often in response to our proposed rule), we believe that many of the remaining utilities will not voluntarily open their systems absent a final rule. *See also* note 266.

[258] *AGD*, 824 F.2d at 1008.

presented numerous additional examples of undue discrimination, which are summarized above, and we set forth below further examples of undue discrimination that have been raised in cases before the Commission.

Many of the examples of discriminatory behavior that have been brought to our attention do not name the specific utilities involved, and many are allegations that are not proven. However, we do not believe that this undermines our finding of unduly discriminatory practices by transmission owners and controllers. We believe that it is only natural that potential transmission customers with an interest in participating in electric markets will be reluctant to name names for fear of being shut out of those markets. CCEM, which identified a wide array of discriminatory behavior its members have experienced, explained that

(w)e do not identify the specific utilities in each example because it is the experience of CCEM members that nearly all transmission owners retaliate by cutting off all communications with anyone that challenges or complains about the rates, terms or conditions at which the owner offers access to its system. Inasmuch as most of the competitive commerce in electric power today is in short-term markets, it is typically not worth the effort of CCEM members or other transmission-dependent entities to file a complaint with the Commission's enforcement staff or in the courts in connection with a transmission owner's discriminatory practices. The deal is lost well before a complaint can be processed and ruled upon.[259]

Other examples of discriminatory behavior have also been raised in proceedings before the Commission. As we explained in detail in the NOPR, transmission-owning utilities have discriminated against others seeking transmission access in a variety of ways, most often subtly and indirectly.[260] For example, delaying tactics have been used to frustrate access. The history of Pacific Gas and Electric Company's (PG&E) attempt to avoid its commitments made to the California owners of the California-Oregon Transmission Project (COTP) is a prime example. The owners had originally planned the COTP to have its southern terminus at the Midway station with Southern California Edison. PG&E convinced them to terminate the project instead at PG&E's Tesla station and indicated that PG&E would provide transmission service the rest of the way south to Midway. PG&E promised this service in 1989 (in Principles). PG&E spent the next four years filing substitute provisions for what it had promised in the Principles.[261] Additional allegations of discriminatory behavior are set forth in Appendix C, which includes allegations made under oath in proceedings at the Commission and allegations made in pleadings and other documents before the Commission.

In addition, to date, the Commission has received 28 section 211 transmission requests.[262] Applicants submit section 211 transmission requests when the transmission provider refuses to provide the requested transmission service. For example, American Municipal Power-Ohio, Inc. (AMP-Ohio) requested Ohio Edison Company (Ohio Edison) to establish additional delivery points to certain of AMP-Ohio's members and to permit the addition of delivery points in the future upon AMP-Ohio's request. Ohio Edison refused AMP-Ohio's request, claiming that it was not a proper request under section 211 because it already provided wholesale transmission to the municipal utilities at issue. In a proposed order, the Commission disagreed with Ohio Edison and ordered Ohio Edison to provide the requested additional delivery points and to entertain future requests by AMP-Ohio for specific delivery points.[263]

Many of the examples of discriminatory actions we are seeing in the electric industry are similar to those we saw in the gas industry. Given our experience, we find that these examples of discriminatory actions are credible and well-founded. Thus, we conclude that there is more than sufficient reason to believe that transmission monopolists currently engage in unduly discriminatory practices, and that they will continue to engage in unduly discriminatory practices, unless we fashion a remedy to eliminate their ability and incentive to do so. In light of the competitive changes occurring in today's electric industry, we believe that the only effective remedy is non-discriminatory open access transmission, including functional unbundling and OASIS requirements, and that it is within our statutory authority to order that remedy.

Further, we disagree with the argument that we are limited to applying a traditional antitrust analysis in determining whether market power exists in the transmission system. While we must take antitrust concerns into consideration in exercising our responsibilities under the FPA, we are not an antitrust court, and our responsibilities are not those of the Department of Justice.[264] We have analyzed the incentives and practices of monopoly transmission owners and controllers in light of the statutory standards and directives of the FPA and, based on our findings, have properly concluded that there is a generic problem that must be remedied.

The Commission also recognizes, as some commenters suggest, that we have, in the past, permitted utilities to file tariffs containing restrictions on transmission service that we are now finding to be unduly discriminatory in this rule and that we found unduly discriminatory in cases since our decision in *AEP*. However, it is entirely appropriate, and indeed necessary, that our application of the FPA's undue discrimination standard evolve over time and adapt to the changing circumstances in the industry. Our prior willingness to tolerate the use of monopoly power over transmission to maintain and aggregate the utility's market power over generation occurred in the context of an industry structured largely as vertically integrated regulated monopolies that supplied all facets of utility service—power supply, transmission, and distribution—as a single monopoly service. Competition generally was not meaningfully available as a means to discipline prices and consumer interests were best served by improving efficiencies of the integrated utilities, subject to cost-based regulation.

Today, the circumstances of the industry are radically different. As explained in detail in Section III, a series of significant economic, regulatory, and technical changes in the power industry has introduced the promise of competitively priced power supplies. The profile of electric power suppliers has expanded to include not just the power supply arms of traditional utilities, but also independent power suppliers, affiliated utility power suppliers selling into territories of other franchise utilities,

[259] CCEM Initial Comments at 18–19. *See also* NIEP Reply Comments at 13 n.31.

[260] FERC Stats. & Regs. at 33,072.

[261] *See* Pacific Gas and Electric Company, 65 FERC ¶ 61,312 at 62,428–30 and n.22, *remanded on other grounds,* Pacific Gas & Electric Company v. FERC, No. 94–70037 (9th Cir. June 23, 1994)(unpublished opinion), *order on remand,* 69 FERC 61,006 (1994).

[262] A list of section 211 applications and the status of each is attached as Appendix A.

[263] American Municipal Power-Ohio, Inc. v. Ohio Edison Company, 74 FERC ¶ 61,086 (1996).

[264] *See, e.g.,* Gulf States Utilities Company v. FPC, 411 U.S. 747, 758–60 (1973); FPC v. Conway Corporation, 426 U.S. 271, 279 (1976); Northern Natural Gas Company v. FPC, 399 F.2d 953, 960 (D.C. Cir. 1968).

and power marketers.[265] This offers the promise of an increasingly competitive commodity market in electric power, in which significant benefits to consumers can be achieved. In the context of an emerging competitive market in generation, discriminatory practices that once did not constitute *undue* discrimination must be reviewed to determine whether they are being used to prevent the benefits of competition in generation from being achieved. Here we find conclusively that they are, and use our remedial authority to ensure that they can no longer occur.[266]

c. Section 211

Comments

Various commenters contend that the enactment of section 211 in essence either removed any authority the Commission might have had under sections 205 and 206 or demonstrates that Congress did not believe the Commission could order wheeling under those provisions.

These commenters assert that the legislative history of the FPA indicates that Congress specifically rejected giving the Commission authority to order wheeling under any circumstances.[267] They further contend that the legislative history of section 211 demonstrates that Congress viewed the authority it granted in section 211 as a strictly limited and entirely new authority for the Commission.[268] Specifically, EEI states that the legislative history of the Energy Policy Act confirms that the expanded authority provided under section 211 was not intended to grant the Commission blanket authority to order wheeling, even as a remedy for anticompetitive conduct. Similarly, Utilities For Improved Transition argues that the legislative history shows that Congress specifically intended to preclude the Commission from ordering tariffs of general applicability under any circumstances. In addition, EEI points to testimony provided by a Commission staff witness before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce in which EEI claims that ''she suggested that an affirmative statement that the Commission had the power to require wheeling on its own motion should be included, possibly in section 211.'' EEI maintains that such suggestion was rejected by Congress in favor of allowing the Commission to order wheeling only upon application.

Detroit Edison, asserting that *Cajun* stands for the proposition that the agency must follow Congressionally mandated procedures, claims that the Commission can order transmission only after going through the procedures of section 211. Detroit Edison also argues that the Commission should incorporate into the final rule the various safeguards of section 211, such as the requirement that the utility receive prior notice, the requirement that transmission service be in the public interest, and the requirement that existing service not be displaced. FL Com further asserts that it was Congressional intent in the Energy Policy Act for wheeling to be ordered on a case-by-case basis pursuant to section 211.[269]

EEI argues that the enactment of section 211 eliminated any authority the Commission had under sections 205 and 206 to order wheeling as a remedy for undue discrimination. It alleges that the Commission failed to discuss the *NYSEG* case concerning the relationship between section 211 and sections 205 and 206 in any meaningful way. According to EEI, the *NYSEG* court concluded that section 211 ''was the only appropriate vehicle under which the Commission could order NYSEG to wheel power for the municipality.'' [270] EEI further resorts to canons of statutory construction to conclude that ''section 211 must be given effect as the more specific provision and must be interpreted to limit the scope of sections 205 and 206.'' [271] In addition, EEI asserts that ''Congress had an opportunity to reject the *NYSEG* court's interpretation of the scope of sections 205, 206 and 211, but instead amended section 211 in a manner that is consistent with the view that mandatory wheeling is to be governed exclusively by section 211.'' Dayton P&L raises similar arguments. It notes the savings provision in section 212(e), but says that Congress ''would have been more specific if it understood that the Commission already had the authority to order wheeling under FPA sections 205 and 206. * * *'' [272]

Associated EC argues that the NOPR appears to exceed the Commission's authority in that it proposes that ''wholesale *buyers* and sellers have 'equal access to the transmission grid.' '' It asserts that ''Section 211(a), however, makes mandatory transmission service available only to '[a]ny electric utility, Federal power marketing agency or any other person generating electric energy for sale for resale.' '' [273]

NE Public Power District argues that sections 211 and 212 of the FPA appear clearly to contemplate a case-by-case approach.[274] NE Public Power District adds that if the Commission believes sections 211 and 212 are inconsistent with the public interest, it can ask Congress to modify those provisions. Allegheny adds that the Commission can order wheeling only under sections 211 and 212 on a company-specific basis and can use sections 205 and 206 only to evaluate the reasonableness of terms and conditions of voluntarily filed agreements or tariffs by public utilities.

Utilities For Improved Transition also claims that sections 211 and 212 override any authority the Commission might have had under sections 205 and

[265] We note that there are now 14 power marketers that are affiliated with public utilities.

[266] We take note of EEI's comments that, at the time of the comments, 30 utilities had filed open access tariffs. They argue, therefore, that the rule is unnecessary. Since their comment was filed, the number of utilities filing some form of an open access tariff has risen to 106. However, while some of these tariffs are based on the NOPR pro forma tariffs, many of these tariffs fall significantly short of the tariff requirements of both the NOPR and this Rule. Even if the tariffs met these requirements, the Rule is still needed to complete the task of eliminating undue discrimination by all public utilities and assuring, to the extent possible, a nationwide open access transmission grid. Indeed, a number of these tariffs were filed for the purposes of securing authority to market power *competitively*. This underscores markedly our fundamental conclusion that prior practices of using monopoly power over transmission to preserve market power over electricity sales has no place in today's industry and must be eliminated to get the benefits of competition to the customers we are required to protect under the FPA.

[267] *E.g.*, EEI, VA Com, Ohio Edison Southern, Utilities For Improved Transition, BG&E.

[268] *See also* NM Com.

[269] *See also* Salt River. Moreover, FL Com states that the Commission should modify its hearing process to better accommodate state PUC participation by: (1) Holding hearings in the affected state; (2) teleconferencing; (3) making free transcripts available to states; and (4) substantially deferring to a state when the state commission has held a hearing on an issue in the case.

[270] EEI quoted the following language from *NYSEG*:

Nor do we suggest that the Commission is powerless to review a wheeling agreement under section 206 without following the requirements of sections 211 and 212. If, after a hearing as required by section 206, the Commission determines that a particular rate, charge or condition is unreasonable, it can order a modification. But where, as here, the modification amounts to an order requiring wheeling, it must be preceded also by determination in accordance with sections 211 and 212. Simply put, we will not allow the Commission to do indirectly without compliance with the statutory prerequisites, what it could not do directly without such compliance. (citing *Richmond Power & Light*).

[271] *See also* VA Com.

[272] *See also* Carolina P&L.

[273] This argument is puzzling. First, section 211 does not control to whom access must be provided under sections 205 and 206. However, even if it did, Associated EC appears to misconstrue eligibility under section 211. An electric utility as defined in the FPA is any person or State agency (including any municipality) which sells electric energy. The definition does not say that electric energy must be re-sold at wholesale. Thus, an electric utility could be a wholesale *buyer* of transmission used to transmit energy for sale at either wholesale or retail.

[274] *See also* Allegheny.

206 to order industry-wide open access. It cites the savings clause in section 212(e) of the FPA as limiting the Commission's authority to order transmission.[275] Utilities For Improved Transition argues at some length that the NOPR does not meet the procedural and substantive standards of sections 211 and 212. It goes on to cite various passages from the legislative history of the Energy Policy Act as supporting the view that Congress intended to eliminate the Commission's authority to order industry-wide open access as a remedy for undue discrimination. According to Utilities For Improved Transition, these passages ''unmistakably show a clear legislative intent to preclude the mandatory transmission that the Commission attempts here * * *.''

Commission Conclusion

We disagree with those commenters that argue that the Energy Policy Act either eliminates our authority under section 206 to remedy undue discrimination by requiring non-discriminatory open access transmission or demonstrates that we never had any such authority. Nothing in sections 211 and 212 or in the legislative history of these sections indicates that Congress intended to eliminate the Commission's other, broader authorities under the FPA. Indeed, section 212(e) specifically provides:

SAVINGS PROVISIONS.—(1) No provision of section 210, 211, 214, or this section shall be treated as requiring any person to utilize the authority of any such section in lieu of any other authority of law. Except as provided in section 210, 211, 214, or this section, *such sections shall not be construed as limiting or impairing any authority of the Commission under any other provision of law*.[276]

Utilities For Improved Transition's argument that the ''Except as provided'' clause limits or impairs the Commission's authority to order transmission service under sections 205 and 206 would make the savings provision meaningless. Moreover, such a reading would be entirely at odds with the underlying purposes of the Energy Policy Act. It would be ironic indeed to interpret the Energy Policy Act as eliminating our long-standing, broad authority to remedy undue discrimination, given the pro-competitive purpose of the statute.

The legislative history also provides no support for the arguments that sections 211 and 212 remove or prove the non-existence of the Commission's authority to remedy undue discrimination by requiring non-discriminatory open access transmission. In fact, virtually every bit of legislative history raised by commenters opposing the NOPR consists of various statements by Senator Wallop, an opponent of expanding transmission access under sections 211 and 212.[277] Such legislative history provides no insight into the meaning of a statute and is given little or no weight by the courts.[278]

The only other legislative history that commenters put forth is the testimony of a Commission staff witness, in 1992 hearings before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce. According to EEI, the witness indicated that an affirmative statement that the Commission could require wheeling on its own motion ''would be needed [in the Energy Policy Act] if Congress intends for the Commission to be able to deal with transmission on its own motion and thereby go further than simply dealing with industry proposals.'' EEI claims that this statement demonstrates that the expanded authority in the Energy Policy Act ''was not intended to grant the Commission blanket authority to order wheeling, even as a remedy for anticompetitive conduct.''

EEI's argument is misleading and disingenuous. It takes the witness's statements out of context, ignoring attendant testimony that ''there are strong legal arguments that the Commission's obligation to protect against undue discrimination carries with it the authority to impose transmission requirements as a remedy for undue preference or discrimination,'' and the extensive legal argument, included in her testimony, in favor of that position—an argument that closely parallels the legal argument the Commission is relying on in this proceeding.[279] Indeed, in the face of such explicit testimony from the staff of the agency required to implement the statute, had Congress intended to limit the Commission's remedial authority under section 206 when it amended section 211, we believe it would have explicitly done so in the language of the statute itself, or at least have indicated its intent to do so in the Conference Report on the Energy Policy Act.[280]

C. Comparability

1. Eligibility to Receive Non-Discriminatory Open Access Transmission

In the NOPR, the Commission proposed to define who is eligible to receive service under a non-discriminatory open access tariff as follows:

A non-discriminatory open-access tariff must be available to any entity that can request transmission services under section 211.[281]

The Commission further explained that ''[u]nder section 211, any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale may request transmission services under section 211.'' [282]

[275] It states that

Section 212(e), however, provides that Sections 211 and 212 limit or impair the Commission's authority under ''other provisions of law'' (a phrase including, obviously, Sections 205 and 206). On the face of the statute—we say again for emphasis: *on the face of the statute*—the Commission therefore does not have the authority to order transmission service outside the provisions of Sections 211 and 212.

Utilities For Improved Transition Initial Comments at 51 (emphasis in original).

[276] 16 U.S.C 824k (emphasis added).

[277] In discussing the electricity provisions of the Energy Policy Act, Senator Wallop declared:

It would be a mistake to take the presence of transmission access provisions in the Conference Report as a sign of change in position on my part or that of the Senate. I would have strongly preferred PUHCA reform without any transmission access provisions, as was the Senate position. However, in order to obtain the very significant benefits of PUHCA reform contained in the Senate bill, it was necessary to accept some of the House transmission access provisions.

138 Cong. Rec. S17615 (daily ed. October 8, 1992).

[278] *See, e.g.,* Shell Oil Company v. Iowa Department of Revenue, 488 U.S. 19, 29 (1988) (*Shell*). In *Shell*, the Court declared:

This Court does not usually accord much weight to the statements of a bill's opponents. ''[T]he fears and doubts of the opposition are no authoritative guide to the construction of legislation.'' *Gulf Offshore Co.* v. *Mobil Oil Corp.,* 453 U.S. 473, 483 (1981) (quoting *Schwegmann Bros.* v. *Calvert Distillers Corp.,* 341 U.S. 384, 394 (1951).

See also Sutherland Statutory Construction § 48.16 at 366.

[279] Hearings on H.R. 1301, H.R. 1543, and H.R. 2224 before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, 102d Cong., 1st Sess. (May 1,2 and June 26, 1991), Statement of Cynthia A. Marlette, Associate General Counsel, Federal Energy Regulatory Commission, Report No. 102–60 at 60 and 61–70. *See also id.* at 106 (''I believe that we have substantial authority under the existing case law to mandate access where necessary to remedy anticompetitive effects.'').

[280] At the time Congress enacted amendments to FPA section 211, it was well aware that the Commission had unexplored authorities under sections 205 and 206 of the FPA to compel wheeling. The only explicit limitations it chose to impose on the Commission's wheeling authorities were those contained in sections 212(g) and (h), which provide that no order ''under this Act'' may be inconsistent with any State law governing retail marketing areas of electric utilities (section 212(g)), or be conditioned upon or require the transmission of electric energy directly to an ultimate consumer (section 212(h)).

[281] FERC Stats. & Regs. ¶ 32,514 at 33,083 (footnote omitted).

[282] *Id.* at 33,083 n.195.

Comments

PSNM believes that the NOPR properly defined customer eligibility. NIEP, on the other hand, believes that the proposed definition is too limited. It argues that the Commission should require public utilities to make transmission service available to all entities engaged in wholesale purchases or sales of power, not just to those ''generating'' power. Utility Working Group requests that the Commission clarify that eligibility is dependent not only on being the type of entity set forth in section 211, but on meeting the requirements of section 212(h) (Prohibition on Mandatory Retail Wheeling and Sham Wholesale Transactions) as well.[283]

We also received several comments related to the applicability of the rule to foreign entities. Canada states that the requirements for comparability and reciprocity should be implemented in a flexible manner to permit Canadian utilities to have fair and competitive access in the U.S. electricity market. Maritime requests that the Commission require Canadian utilities who wish to participate in the U.S. market to offer other utilities the same privileges they receive in the United States. Southwestern argues that transmission *to* a foreign country is in interstate commerce and that a utility should therefore accommodate this type of transmission request under its open access tariff. El Paso argues that the Commission does not have the authority to condition access to foreign countries, but states that if the Commission nevertheless exercises such authority it should do so on a case-by-case basis. Destec asserts that

> the posturing of Ontario Hydro before U.S. regulators pleading for open access and non-discriminatory transmission treatment—even for extra-territorial entities, should be met with a strong reply that such provisions should also be afforded transmission dependent entities on the Canadian side of the border. Ontario Hydro's aggressive pursuit of U.S. market opportunities while simultaneously blocking competitors through the control of their transmission assets can not be ignored.

Commission Conclusion

In the Final Rule pro forma tariff the Commission has modified the definition of ''eligible customer'' to address concerns that in some respects the NOPR definition was too limited and in other respects it was too broad. This includes amended language to clarify that any entity engaged in wholesale purchases or sales of energy, not just those ''generating'' electric power, is eligible. It also includes clarification that entities that would violate section 212(h) of the FPA (prohibition on Commission-mandated wheeling directly to an ultimate consumer and sham wholesale transactions) are not eligible. The language also has been modified to provide that foreign entities that otherwise meet the eligibility criteria may obtain transmission services. Further, it has been modified to provide for service to retail customers in circumstances that do not violate FPA section 212(h).[284]

Persons that would be eligible section 211 applicants also would be eligible under the open access tariffs. Section 211 applicants may be any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale.

Section 3(22) of the FPA, as amended by the Energy Policy Act, defines ''electric utility'' to mean

> any person or State agency (including any municipality) which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency.

Thus, as we have previously noted, municipal utilities are electric utilities simply by the terms of the statute.[285] In addition, we have also found that cooperatives and marketers are electric utilities as defined in the FPA.[286] Other entities that fall within the definition include IOUs, IPPs, APPs, and QFs that sell electric energy.

We do not believe that entities that engage solely in brokering should be eligible. Such brokers do not take title to electricity and therefore do not engage in the sale of electric energy; nor do they generate electric energy for sale for resale.[287] Although such brokers are not eligible under the tariffs, they will be able to arrange deals because they will have access to the OASIS of all public utilities and will be able to solicit information from the relevant transmission service providers under the terms of the applicable tariffs.

We clarify that foreign entities that otherwise meet the eligibility criteria must be eligible to receive service under the non-discriminatory open access transmission tariffs.[288] We are making this determination pursuant to our authority under section 206 of the FPA to remedy undue discrimination. As we explained in the NOPR, market power through the control of transmission can be used discriminatorily to block competition. Customers in the United States should not be denied access to cheaper supplies of electric energy, whether such electric energy is from a domestic source or a foreign source. By making non-discriminatory access available to foreign entities that otherwise meet the eligibility criteria, we are assuring that customers in the United States have access to as many potential suppliers as possible. This should result in increased competition and lead to customers paying the lowest possible prices for their electric energy needs. To the extent that such an entity obtains access, however, we emphasize that it would be subject to all of the terms and conditions of the applicable open access tariff, including the *requirement* that it provide reciprocal service.

Finally, we have reconsidered our NOPR position that would have limited eligibility to wholesale transmission customers. As we explained in the NOPR, the Commission's jurisdiction extends to *all* unbundled transmission in interstate commerce by public utilities. It is irrelevant to the Commission's jurisdiction whether the customer receiving the unbundled transmission service in interstate commerce is a wholesale or retail customer. Thus, if a public utility voluntarily offers unbundled retail access in interstate commerce or a state retail access program results in unbundled retail access in interstate commerce by a public utility, the affected retail customer *must* obtain its unbundled transmission service under a non-discriminatory transmission tariff on file with the Commission. Though the Commission may approve a separate retail transmission tariff when some variation is necessary or appropriate to meet local concerns,[289] we generally see no reason why retail transmission tariffs necessarily must be different from wholesale transmission tariffs. For that reason, we anticipate that in many

[283] Section 212(h) (Prohibition on Mandatory Retail Wheeling and Sham Wholesale Transactions).

[284] We emphasize that *any* transmission customer must follow prudent utility practices so as to assure reliability.

[285] New Reporting Requirement Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibility Under the Energy Policy Act of 1992, and conforming and Other Changes to Form No. FERC–714, Order No. 558–A, 65 FERC ¶ 61,324 at 62,451 n.12 (1993).

[286] Order No. 558, FERC Stats. & Regs. ¶ 30,980 at 30,895–96, *reh'g denied*, 65 FERC ¶ 61,324 (1993) (cooperatives are electric utilities); *AES Power, Inc.*, 69 FERC ¶ 61,345 at 62,297 (1995) (power marketer is an electric utility, *i.e.*, a person ''which sells electric energy'').

[287] *See, e.g.*, Citizens Energy Corporation, 35 FERC ¶ 61,198 at 61,452–53 (1986).

[288] In making this determination, we are not deciding whether these entities are eligible entities under section 211(a) of the FPA.

[289] *See* Section IV.I.

circumstances the same open access tariff that serves wholesale customers will be equally appropriate for retail transmission customers. Therefore, unless the Commission has specifically permitted a separate retail tariff, eligible customers under the Final Rule pro forma tariff must include unbundled retail customers.[290] We discuss this further in Section IV.I.

While the rates, terms, and conditions of all unbundled transmission service will be subject to a Commission-authorized tariff, we will, in appropriate circumstances, give deference to state recommendations regarding rates, terms, and conditions for retail transmission service or regarding the proper transmission cost allocation to be used between retail and wholesale customers when state recommendations are consistent with our open access policies. This is also discussed further in Section IV.I.

Moreover, we are mindful of the fact that we are precluded under section 212(h) from ordering or conditioning an order on a requirement to provide wheeling directly to an ultimate consumer or sham wholesale wheeling. We therefore clarify that our decision to eliminate the wholesale customer eligibility requirement does not constitute a requirement that a utility provide retail transmission service. Rather, we make clear that if a utility chooses, or a state lawfully requires, unbundled retail transmission service, such service should occur under this tariff unless we specifically approve other terms.

2. Service That Must be Provided by Transmission Provider

In the NOPR, the Commission proposed that a public utility must offer to provide any point-to-point or network transmission service whether or not the utility provides itself that service:

The Commission therefore proposes that all public utilities must offer both firm and non-firm point-to-point transmission service and firm network transmission service on a non-discriminatory open access basis in accord with the proposed rule and the attached appendix tariffs. The Commission believes that a utility's tariff must offer to provide any point-to-point transmission service and network transmission service that customers need, even though the utility may not provide itself the specific service requested.[291]

Comments

EGA and SMUD agree that a transmission owner should offer any transmission service it is able to provide, even if it does not use the service itself.

Public Generating Pool, an association of consumer-owned electric utilities, appears concerned that the Commission may interpret comparability broadly to require a utility to offer the same service provided by another utility or to offer service generally available in a region. Thus, it recommends that a third party seeking more service than a utility provides itself be required to resort to the section 211 process.

Commission Conclusion

Initially, we note that, with the possible exception of small utilities (which may qualify for a waiver, *see infra*), we have seen no evidence that public utilities are incapable of reasonably providing the services required in the Final Rule pro forma tariff. Nor have we seen evidence that utilities able to provide these services to themselves are choosing to forego such services. In short, we are not convinced that there is an appreciable difference, if any, among the services required in the pro forma tariff, the services utilities are able to provide, and the services they actually provide themselves.

To the extent these services do differ, however, we explicitly adopt the proposal set forth in the NOPR. Thus, a public utility must offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others. Because a public utility that is reasonably capable of providing transmission services may provide itself such services at any time it finds those services desirable, it is irrelevant that it may not be using or providing that service today. Moreover, a public utility must offer these transmission services whether or not other utilities may be able to offer the same services and whether or not such services are generally available in the region (waiver of these requirements for small utilities is discussed in Section IV.K.2.).[292] However, if a customer seeks a customized service not offered in an open access tariff, a customer may, barring successful negotiation for such service, file a section 211 application.

3. Who Must Provide Non-Discriminatory Open Access Transmission

In the NOPR, the Commission proposed to require all ''public utilities'' owning and/or controlling facilities used for transmitting electric energy in interstate commerce to file open access transmission tariffs.[293] We explained that we could not require all ''transmitting utilities'' to file open access tariffs under sections 205 and 206 because we do not have jurisdiction over non-public utilities under these sections.

Comments

Several commenters argue that the open access requirement must be applied to non-jurisdictional utilities that own interstate transmission facilities.[294] Power Marketing Association recognizes that this raises difficult legal issues and suggests that the Commission support legislation to expand the Commission's authority over non-jurisdictional utilities. Minnesota P&L argues that if the requirement is not applied to all entities that own transmission, jurisdictional and non-jurisdictional entities owning joint transmission facilities will be competitively disadvantaged due to unequal pricing. Union Electric argues that unless the requirement is extended to the 56 non-jurisdictional entities operating control areas, discrimination in the wholesale power markets will increase.

A number of municipal commenters assert that the NOPR overlooks transmission assets jointly owned by jurisdictional and non-jurisdictional utilities.[295] They argue that agreements regarding use of these assets often contain provisions prohibiting third-party power transfers. They further argue that such provisions should be nullified, and the joint owners should be required to develop equitable methodologies to allocate wheeling revenues among themselves.

Several cooperatives urge the Commission to clarify that contracts among their constituent cooperatives are not subject to any unbundling of existing contracts.

Commission Conclusion

Our authority under sections 205 and 206 of the FPA permits us to require only public utilities to file open access tariffs as a remedy for undue discrimination. We have no authority

[290] The Commission has no authority to order retail transmission directly to an ultimate consumer or to order ''sham'' wholesale transmission. *See* FPA section 212(h). However, if such access occurs voluntarily or as a result of a state program, the rates, terms, and conditions of the access are within our exclusive jurisdiction if the service is provided by a public utility.

[291] FERC Stats. & Regs. ¶ 32,514 at 33,079.

[292] Requirements for ancillary services are discussed in Section IV.D.

[293] FERC Stats. & Regs. ¶ 32,514 at 33,049.

[294] *E.g.*, Minnesota P&L, Power Marketing Association.

[295] *E.g.*, Springfield.

under those sections of the FPA to require non-public utilities to file tariffs with the Commission.

However, we are concerned that if non-public utilities do not provide access, there will remain a patchwork of ''open'' and ''closed'' transmission systems and the potential for distortions in wholesale bulk power markets. We believe that certain mechanisms exist that will help to alleviate these problems.

First, as we explained in the NOPR, broad application of section 211 will provide wider access to bulk power markets.[296] Under section 211, eligible entities may seek transmission service from ''transmitting utilities,'' which section 3(23) of the FPA defines as ''any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.'' We believe that section 211 provides us with authority to require the same *quality* of transmission service as sections 205 and 206, though the procedural path is more cumbersome. Thus, section 211 provides access to transmission systems owned or operated by non-public utilities.[297]

Second, as we explained in the NOPR, our reciprocity requirement is designed to provide the widest possible use of the nationwide transmission grid:

> The purpose of this provision is to ensure that a public utility offering transmission access to others can obtain similar service from its transmission customers. It is important that public utilities that are required to have on file tariffs be able to obtain service from transmitting utilities that are not public utilities, such as municipal power authorities or the federal power marketing administrations that receive transmission service under a public utility's tariff.[298]

Finally, again as we explained in the NOPR, the formation of RTGs should speed the development of competitive markets and involve more non-public utilities in the provision of non-discriminatory open access transmission.[299] In approving RTGs, our policy has been to require all members, whether or not they are public utilities, to offer comparable transmission services at least to other members.

We recognize that these solutions are not perfect. However, given the difficulties inherent in the statutory scheme, we believe they will go a long way toward effectuating transmission access by non-public utilities.

One further issue involving non-public utilities concerns jointly owned transmission facilities. We will not allow public utilities that jointly own interstate transmission facilities with non-jurisdictional entities to escape the requirements of open access. We will require each public utility that owns interstate transmission facilities jointly with a non-jurisdictional entity to offer service over its share of the joint facilities, even if the joint ownership contract prohibits service to third parties. We urge such public utilities to seek mutually agreeable revisions to their agreements to permit third-party access over all, or at least their share, of the facilities. For those joint ownership arrangements that include restrictions on the usage of jointly owned transmission facilities by third parties, we will require the public utilities, in a section 206 compliance filing, to file with the Commission, by December 31, 1996, a proposed revision (mutually agreeable or unilateral) to its contract with the non-jurisdictional owner(s). This revision must be designed at a minimum to permit third parties to use the public utility's share of the joint facilities in accordance with this Rule and must provide for any needed cost allocation procedures between the public utility and the non-jurisdictional owner(s).

4. Reservation of Transmission Capacity by Transmission Customers

In the NOPR, the Commission set forth the information that a requester of transmission service would have to submit with a service request. We recognized that there may have to be a limit, for competitive reasons, on the information required, but also recognized the need to assure that no customer would reserve scarce capacity and then hold it without using it.[300] To avoid forcing transmission customers to reveal unnecessary details of their purchase or sales transactions, the Commission discussed several less restrictive options: (1) Allow the transmission provider to use or sell the capacity while it is unused, (2) have a pool that clears the short-term market, and (3) require the customer to begin using the capacity within some specified period or lose its reservation rights. The Commission requested comments on these and other possible approaches.

Comments

Unused or Unneeded Transmission Capacity

Many commenters recommend a use-it-or-lose-it rule (*i.e.*, a transmission customer must use its reserved transmission capacity or lose its rights to that capacity).[301] Several commenters also recommend a number of restrictions on capacity reservations to reduce incentives to hoard or to cherry-pick (request to reserve firm capacity only during peak hours of peak seasons) existing transmission capacity. These include: (1) Allow requesters to reserve a place in the queue with a right of first refusal over later competing requests; (2) impose a take-or-pay charge on reservations and deny reservation holders the right to revenue sharing if they do not schedule or assign their rights; (3) limit the time period for reservations; (4) limit how far in advance reservations may be made for both non-firm and firm services; (5) maintain a price cap on the resale of transmission; (6) require multi-year reservations to be for sequential periods; and (7) require a nonrefundable fee for advance reservations of service.[302] Southwestern suggests that transmission tariffs include a provision that prevents transmission customers and the transmission provider from reserving and tying up firm transmission capacity for speculative wholesale transactions.[303]

On the other hand, PSNM believes that a use-it-or-lose-it approach is inappropriate because any prudent utility that has reserved capacity would seek to sell the service it is not using so as to recover some portion of its fixed costs. Wisconsin P&L argues that a use-it-or-lose-it approach would not work, would be difficult to administer, and may be anticompetitive.[304] Central Illinois Public Service asserts that a reservation holder has little incentive to hoard capacity because other customers can use the capacity on a non-firm basis during times when a reservation holder does not schedule power. It warns that

[296] FERC Stats. & Regs. ¶ 32,514 at 33,050 and 33,092–93.

[297] As discussed in the NOPR, sections 211 and 212 require that applicants specify only rates, terms, and conditions of service, not specify transactions. Thus, applicants can file requests for tariffs to accommodate future, currently unspecified transactions, similar to the open access tariffs required by this Rule.

[298] FERC Stats. & Regs. ¶ 32,514 at 33,089.

[299] *Id.* at 33,095.

[300] *Id.* at 33,090.

[301] *E.g.*, Consumers Power, Northern States Power, PacifiCorp, Oklahoma G&E, Allegheny Power, ELCON, Public Service Co of CO.

[302] *E.g.*, Northern States Power, VEPCO, Utilities For Improved Transition, PacifiCorp, Arizona Public Service, Dairyland, Montaup, Illinois Power, South Carolina E&G, Florida Power Corp, KU.

[303] *See also* NRECA.

[304] Wisconsin P&L notes, however, that a possible exception exists where a user could block the efficient transfer of power and then market its own power at a premium price.

giving the transmission operator the ability to schedule unused capacity may result in undue influence and the exercise of market power. CA Energy Com maintains that, while reassignment would help prevent hoarding, it would not assure efficient use of the full transmission network.

Use of Pooling Arrangements To Prevent Improper Reservations

Allegheny Power contends that a pooling arrangement could provide an incentive to hoarders to release capacity during a shortage. It suggests that capacity could be auctioned within a pool of available capacity. However, it acknowledges that an auction would be tantamount to allowing the network owner to sell transmission service at unregulated rates.

PacifiCorp does not believe that a pooling arrangement would prevent capacity hoarding unless nonsequential reservations are prohibited. ELCON contends that a use-it-or-lose-it rule would be fairer and more effective than pooling.

Commission Conclusion

Upon further consideration, we conclude that firm transmission customers, including network customers, should not lose their rights to firm capacity simply because they do not use that capacity for certain periods of time. Firm transmission customers that have reserved capacity and paid a reservation charge generally do not use the entire amount of reserved capacity at all times. This does not mean, however, that they must permanently return the unused amount to the utility. In the absence of evidence of hoarding or other anticompetitive practices, we will not limit the amount of transmission capacity that a customer may reserve. Firm transmission customers are in the best position to know the levels of electric energy they will be transmitting and the level of flexibility they need in carrying out their transmission activities. Indeed, when they are not using their reserved capacity, firm transmission customers remain obligated to pay the utility a reservation charge that covers all of the utility's fixed costs associated with the reserved capacity.[305]

Moreover, the possibility that a customer will reserve capacity and then hold it without using or reassigning it is mitigated because the utility is free to schedule and sell any unscheduled firm point-to-point transmission capacity on a non-firm basis to any entity eligible to receive such service under the utility's tariff. We also note that it is in the economic self interest of reservation holders to make available unused capacity to the market.[306]

We recognize that situations could arise in which a customer unlawfully withholds capacity. That is, a transmission customer could retain capacity in a way that could have an anticompetitive effect. For example, a transmission customer may reserve certain capacity simply to prevent everyone else from using it and to make its own generation the only alternative available to the market. However, as described above, we believe that the incentives are such that parties are more likely to release unneeded capacity and that a generic remedy is therefore unnecessary. Any substantial allegations that indicate that a transmission customer is withholding scarce capacity in a way that has an anticompetitive effect would be addressed under section 206. If we found such allegations to be true, we could order the customer to return the capacity reservation right to the transmission operator. This approach should allay concerns that a customer may reserve scarce capacity and not use it, without forcing customers to demonstrate need or to reveal details of individual transactions.

5. Reservation of Transmission Capacity for Future Use by Utility

Comments

EEI and many IOUs argue that native load and network transmission customers should have first priority to existing capacity for their reasonably forecasted load requirements because that capacity was constructed to provide service to them and was paid for by them.[307] EEI contends that such priority ensures equity and comparability based on past and future cost responsibility for the system. Similarly, Florida Power Corp and PECO contend that third-party customers should not be allowed to use transmission capacity that native load customers would grow into within a reasonable planning horizon.

Other commenters disagree, asserting that available transmission capacity must be determined in the same manner for all customers and that utilities should not be permitted to reserve capacity for their own uses.[308] NIEP argues that utilities should not be permitted to lock up available transmission capacity over valuable transmission paths and then require transmission requesters to pay for the cost of incremental transmission upgrades. This would let the utility avoid incremental transmission charges on its system. Oklahoma G&E argues that existing available transmission capacity should be made available until it is needed for native load growth. Utilicorp states that transmission owners should not be permitted to set aside capacity for sales or purchases of economy energy. CCEM argues that the centerpiece of comparability is that all transmission customers, including the merchant operations of the transmission owner, take service from available capacity pursuant to the same tariffs. CCEM adds that allowing utilities to reserve capacity based on forecasted retail and network loads creates an incentive for them to over-forecast their load to the detriment of all others. NRECA suggests that the need to maintain reliability should not perpetuate transmission providers' preferential treatment of their own transactions. It also recommends that, during periods when facilities are constrained, access be allocated based on a combination of past actual use and planned future use.

Commission Conclusion

We conclude that public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon. However, any capacity that a public utility reserves for future growth, but is not currently needed, must be posted on the OASIS and made available to others through the capacity reassignment requirements, until such time as it is actually needed and used.

In response to arguments raised by several commenters that existing requirements customers should have future rights to existing capacity beyond the terms of their contracts because of their historical use, as discussed previously, we believe existing customers should have a right of first refusal to capacity they previously used, if they are willing to match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time, and to accept a contract term at

[305] A reservation charge would assure that the utility fully recovers its fixed costs associated with the transmission customer's reserved transmission capacity.

[306] *See* Section IV.C.6.

[307] *E.g.*, NYPP, Public Service E&G, Sierra Pacific Power, Ohio Edison. Sierra Pacific Power asserts that a utility should be permitted to retain capacity for native load use over the pertinent planning period. El Paso adds that the Commission should allow utilities the opportunity to reserve capacity for anticipated uses that, although not firm, are necessary to maintain reliability.

[308] *E.g.*, NIEP, CCEM, Conservation Law Foundation.

least as long as that offered by another potential customer.[309]

6. Capacity Reassignment

In the NOPR, the Commission proposed that a tariff must explicitly permit reassignment of firm service entitlements.[310] We explained that reassignment of capacity rights could have a number of benefits: (1) Helping transmission users manage financial risk, (2) reducing transmission providers' market power by enabling transmission customers to compete with them, and (3) improving capacity allocation when capacity is constrained and some market participants value capacity more than current capacity holders. We requested comments on whether the current price cap on resale should be modified or eliminated and whether the transmission services described in the NOPR are suitable for reassignment.

Comments

General

Many commenters favor capacity reassignment and the development of secondary markets.[311] However, WP&L notes that reassignments should not be permitted over constrained interfaces if the source or destination of power changes, and LA DWP opposes unrestricted reassignment because it could cause tax-exempt financing problems for many public power utilities.

Many IOUs argue that the same terms and conditions of service applied to IOUs should be applied to resellers of transmission services.[312] Arizona Public Service, however, asserts that all unused transmission rights should not be assignable, but should be made available to others in a manner consistent with the contract supporting the rights. It argues that a network user experiencing an off-system network shutdown should be required during the outage to make available to others the path from the point that the power enters the system to its load. It also contends that firm transmission customers should be required to post their unused rights on an EBB or RIN.

Several commenters oppose mandatory reassignment of firm capacity rights.[313] NEPCO declares that if a customer is willing to pay for its reserved capacity, it should not be forced to reassign unused capacity. Nebraska Public Power District believes that mandatory reassignment could cause problems for publicly-owned utilities. It further asserts that in the gas industry the Commission did not allow the unregulated reassignment regime it proposes for the electric industry.

SoCal Edison argues that when a transmission customer resells transmission capacity, it should not be released from its contractual obligation to the transmission provider. It notes that under traditional contract law, a party to a contract cannot escape its obligations by delegating them to another.

Price Caps

Most commenters addressing this issue support retaining the existing price cap on reassignments or resales.[314] Generally, these commenters believe that the price cap is necessary to prevent customers from speculating or hoarding capacity in anticipation of its value increasing. Public Service Co of CO believes that allowing assignments of capacity at prices greater than cost could prevent a transmission provider from offering firm capacity for legitimate long-term transactions. TDU Systems states that a cap should remain until the secondary market in the relevant geographic market has been shown to be competitive. PA Com states that turning available capacity into a spot market would tie up capacity that might otherwise be used on a day-to-day basis and for emergencies. Still other commenters argue that customers should not be allowed to sell the capacity for more than the transmitting utility could charge.[315] Allegheny argues that any rule that allows resale of transmission capacity at a higher price than the transmission provider can achieve is ''patently illogical and probably illegal.'' Several utilities, including Allegheny and CSW, contend that if resellers can market transmission services at market rates, then transmission owners must be given the same opportunity.

Duquesne and United Illuminating argue that the price cap should be modified so that third parties are allowed to resell capacity at the higher of embedded costs or opportunity costs.[316] Duquesne notes that such a provision would be comparable to the option transmitting utilities now have and would be economically efficient because it would encourage the firm capacity owner with the lowest opportunity cost to resell its capacity.

A few commenters argue that the price cap should be eliminated.[317] IL Com claims that capacity will be made available to the entity that values it most and that an uncapped resale market cannot lead to more market power because an efficient secondary market cannot be monopolized. Con Ed agrees that if the secondary market is competitive, all entities should be allowed to sell at market-based rates.[318] CT DPUC argues that there should not be a price cap; instead, it would prefer that those holding transmission rights not be allowed to withhold use of any portion of their reserved transmission capacity in the actual moment-by-moment operation of the grid.

Creditworthiness Standards

Of those commenting on the appropriate creditworthiness standards for replacement customers (assignees), all favor allowing the transmission provider to use reasonable credit procedures to assure that the replacement customer is financially sound.[319] NYSEG suggests that, at a minimum, the same creditworthiness criteria should be applied to the replacement customer as are applied to the original customer. Oglethorpe recommends that the assignee be required to commit to comply with all customer obligations and to pay for any additional costs resulting from the assignment.

Liability for Payment

Commenters split on whether the original customer or the replacement customer should be liable to the transmitting utility for payment for the service. One group of commenters believes that the original customer should remain liable for all costs and for the performance of all obligations.[320] Another group of commenters believes that the original customer should be relieved of financial responsibility, at least under certain circumstances.[321] For

[309] *See* Section IV.A.5.

[310] FERC Stats. & Regs. ¶ 32,514 at 33,088.

[311] *E.g.*, PacifiCorp, DOJ, NIEP, ELCON, United Illuminating, DOD, WP&L, FTC. OK Com and FL Com favor reassignment of capacity, but express concerns that reliability not be affected.

[312] *E.g.*, Northern States Power.

[313] *E.g.*, NEPCO, Nebraska Public Power District.

[314] *E.g.*, NRECA, Montana Power, PacifiCorp, NYSEG, PA Com, Idaho, Public Service Co of CO, FPC, Entergy, TDU Systems, Duke, Cajun, CVPSC, Oglethorpe, Minnesota DPS. FL Com argues that the price of reassignment should be capped at the contract selling price. WP&L argues that the price cap should be raised to the maximum rate allowed in the tariff under which the user purchased the original service.

[315] *See also* Minnesota DPS.

[316] *See also* Midwest Commissions, SMUD, CCEM.

[317] *E.g.*, IL Com, NEPCO, Consumers, American Wind.

[318] If the market is not competitive, however, Con Ed maintains that the cap should be retained for all entities.

[319] *E.g.*, PacifiCorp, NYSEG, Oglethorpe.

[320] *E.g.*, Oglethorpe, NSP.

[321] *E.g.*, NYSEG, Entergy, TDU Systems, Turlock, American Wind.

example, NYSEG asserts that the original customer should be relieved of its obligations upon the execution of a new service agreement between the new customer and the provider. TDU Systems contends that the original customer should be relieved of future liability where the replacement customer meets the transmission provider's creditworthiness standards. Entergy argues that the original customer should remain liable until all obligations are fulfilled.

Commission Conclusion

After reviewing the comments, we conclude that a public utility's tariff must explicitly permit the voluntary reassignment of all or part of a holder's firm transmission capacity rights [322] to any eligible customer.[323] Reassignment may be on a temporary or permanent basis, and must be subject to the conditions and requirements discussed below.

Allowing holders of firm transmission capacity rights to reassign capacity will: (1) Help them manage the financial risks associated with their long-term transmission commitments, (2) reduce the market power of transmission providers by enabling customers to compete, and (3) foster efficient capacity allocation. We offer below a number of clarifications and further explanations in response to concerns raised by commenters.

(1) Reassignable Transmission Services

We conclude that point-to-point transmission service, because it sets forth clearly defined capacity rights, should be reassignable. As for network transmission service, we conclude that there are no specific capacity rights associated with such service, and thus, network transmission service is not reassignable.

(2) Terms and Conditions of Reassignments

a. General

In effecting a reassignment, the assignor does not have to return its capacity entitlement to the original transmission provider, but may deal directly with an assignee without involvement of the transmission provider. However, an assignee must meet the eligibility standard established by this Rule and must comply with the reliability criteria of the original transmission provider. Any such transaction must be posted on the transmission provider's OASIS within a reasonable time after its effective date. Alternatively, the assignor may, if it wishes, request the transmission provider to effect a reassignment on its behalf.[324] In such a situation, the transmission provider must immediately post the available capacity on its OASIS. The transmission provider must assure that any revenues associated with the reassignment are credited to the assignor.[325]

b. Contractual Obligations

Assignors and assignees may contract directly with each other, but the assignor will remain obligated to the transmission provider. This obligation extends to any penalties or other charges incurred by the assignee in its use of the reassigned capacity. The assignee will be liable solely to the assignor, and should it not meet its obligations, the assignor may cancel the assignment under their contract.

If the transmission provider and the original customer mutually agree, we will permit alternatives to the above approach. For example, the transmission provider could agree to relieve the original customer of payment liability for the term of the reassignment and permit the assignee to pay the provider directly.

In the case of a permanent reassignment, the transmission provider should not unreasonably refuse to release the assignor from liability if the assignee meets the transmission provider's creditworthiness requirements as set forth in its tariff and agrees to pay the price the assignor is obligated to pay the transmission provider.

c. Price Cap

We conclude that the rate for any capacity reassignment must be capped by the highest of: (1) The original transmission rate charged to the purchaser (assignor), (2) the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment, or (3) the assignor's own opportunity costs capped at the cost of expansion (Price Cap). We remain convinced that we cannot lift the Price Cap and permit reassignments at market-based rates. Based upon the information available in this proceeding, we are unable to determine that the market for reassigned capacity is sufficiently competitive so that assignors will not be able to exert market power. Thus, we will not permit an assignor to reassign capacity at a rate in excess of the Price Cap. Assignees must agree, in contracting with the assignor, that the firm transmission capacity they will use is subject to the Price Cap.

7. Information Provided to Transmission Customers Comments

Many commenters argue that in an open access, competitive environment, confidential and proprietary information should not be made publicly available through a RIN.[326]

Several utilities assert that the existing reporting requirements are sufficient to support the comparability requirements of the proposed rule, with some modifications.[327] They note that the Commission's audit authority and complaint process will help enforce comparability requirements.[328] Central Illinois Public Service states that, with the availability of pricing and transaction information through the RIN, no further reporting requirements are necessary. IL Com states that additional reporting should be required only if clear evidence emerges of discriminatory use of the transmission system. Dominion Resources adds that users have no need for utility planning information and data on generator status and that disclosure of such information would place owners at a competitive disadvantage. VEPCO opposes the disclosure of any commercially sensitive information to marketers, including the utility's power marketing employees.

On the other hand, several commenters argue that the information submitted by public utilities may not be adequate. For example, APPA argues that the Commission should scrutinize closely cost functionalization by utilities to assure that plant in service is properly booked. Others recommend that the Commission put in place a monthly pass-through of transmission-related operating income for all classes of customers receiving firm transmission service, rather than rely on the current practice of reducing test year

[322] The transmission provider has the same rights as any other potential assignee to obtain capacity that is posted on an OASIS or to negotiate with the assignor for any capacity the assignor seeks to assign.

[323] The public utility's tariff shall not preclude an assignor from including a right of recall in its agreement with an assignee.

[324] The assignor may also request the transmission provider to provide the billing and payment services for the reassignment. The parties would negotiate terms for such an arrangement, including a fee for the transmission provider. If an assignor is a public utility, it will have to have on file with the Commission a rate schedule governing reassigned capacity.

[325] Any expenses that the public utility incurs in carrying out the capacity assignment program would simply be included in its cost of service.

[326] Similar arguments with respect to the information that public utilities must provide to the Commission in standard reports (*e.g.*, Form No. 1) are addressed later in this Final Rule.

[327] *E.g.*, PacifiCorp, NYSEG, NSP.

[328] *See also* PA Com.

cost of service by revenues booked to Accounts 456 and 447. Industrial Energy Applications recommends that utilities be required to file quarterly reports with the Commission that detail the transmission services and the pricing of their off-system power supply transactions, as an incentive to comply with the Commission's rule.

Commission Conclusion

We conclude that all necessary transmission information, as detailed in the OASIS final rule, must be posted on an OASIS. With respect to generation information, we will require, consistent with the OASIS final rule, that information needed to verify opportunity/redispatch costs be provided, on request, to the transmission customer charged. We will not require this information, or any other generation information,[329] to be posted on an OASIS.[330]

8. Consequences of Functional Unbundling

a. Distribution Function

The NOPR proposed functional unbundling of wholesale generation and wholesale transmission so that the public utility as a wholesale seller could not gain an undue advantage from its transmission ownership. We did not propose to further unbundle the retail transmission and distribution functions from the wholesale transmission function.

Comments

A number of commenters assert that utilities should be required to unbundle—either functionally or corporately—the distribution function from the transmission function. ELCON argues that unbundling distribution would help delineate state and Federal jurisdiction, facilitate the establishment of transmission pricing, avoid cross-subsidization, and prepare for the customer choice (retail wheeling) programs that will be implemented by states in the future. It contends that functional distinctions between wholesale and retail service should be minimized.[331]

Other commenters, however, oppose establishing a separate distribution function. DOD asserts that the Commission can address any problems that arise by enforcing the terms of open access tariffs and that the Commission should not intrude into state ratemaking.[332]

Various state commissions question the workability and desirability of a functional test to determine the dividing line between retail transmission and local distribution.[333] CA Com recommends that, to avoid jurisdictional uncertainty surrounding functional unbundling, the Commission adopt a functional test for local distribution. Under this test, vertically integrated utilities that chose to unbundle into separate operating companies, including a local distribution company that sells only at retail, could establish a workable bright line between state and Federal authority without engaging in the arduous task of differentiating transmission from distribution.

Certain IOUs echo the jurisdictional concerns raised by the state commissions.[334] They believe that the unbundling of the distribution function would create significant jurisdictional problems. Pacificorp also argues that unbundling of the distribution function would create significant jurisdictional conflict with respect to cost allocation.

Commission Conclusion

We conclude that the additional step of functionally unbundling the distribution function from the transmission function is not necessary at this time to ensure non-discriminatory open access transmission. Our approach to assuring such open access has two broad requirements: (1) Functional unbundling of transmission and generation (which includes separately stated rates for generation, transmission, and ancillary services, and a requirement that a transmission provider take service under its own tariff), except for bundled retail service and (2) an OASIS with standards of conduct. We believe that additional requirements are not needed now. We further address in Section IV.I the concerns raised regarding our proposed tests to distinguish transmission and local distribution.

b. Retail Transmission Service

Comments

The majority of commenters addressing this issue believe that unbundling retail service is unnecessary to establish a competitive market and to achieve non-discriminatory open access transmission.[335] For example, PSNM argues that the Commission is not as well situated as are state regulators to oversee and supervise local reliability issues for retail customers. Central Illinois Public Service argues that due to the nature of transmission facilities and operations, it is not possible for the transmission provider to discriminate between the provision of wholesale and retail firm service. Several IOUs further contend that because the Commission is specifically precluded from mandating retail wheeling and has no authority over bundled retail service, the Commission cannot require retail service to be provided.[336]

In contrast, some commenters argue that functional unbundling must apply to all transmission service in interstate commerce provided by public utilities, including the transmission component of bundled retail sales.[337] They believe that this is necessary to achieve comparability. For example, CCEM asserts that if the distribution function is not unbundled, the result will be service under two separate arrangements—an explicit wholesale transmission tariff filed at the Commission and an implicit retail transmission tariff governed by a state regulatory body. According to CCEM, failure to unbundle retail transmission will allow transmitting utilities to manipulate how they characterize and account for their own uses of transmission. ABATE contends that the Commission, for efficiency reasons, should encourage states to permit retail access. It asserts that the Commission must adopt a policy that signals to states how rates, terms, and conditions of retail service will be established; once a state sets such parameters, the Commission should review them.

Commission Conclusion

Although the unbundling of retail transmission and generation, as well as wholesale transmission and generation, would be helpful in achieving comparability, we do not believe it is necessary. In addition, it raises numerous difficult jurisdictional issues

[329] The prices of some ancillary services, which are posted on the OASIS, are based on generation costs, however.

[330] Because the Commission establishes many generation and all transmission rates on a cost basis, the Commission also will continue to need the information that it collects in Form No. 1 and other standard forms from public utilities to assure that the rates are just and reasonable. As we explain later in this Final Rule, the information provided in those forms is public information that is available to any transmission customer. However, because of the competitive changes occurring in the electric industry, we recognize that there may be a need to reexamine the information we collect from public utilities through the Form No. 1.

[331] *See also* Environmental Action, Missouri Basin MPA, Texaco, EGA, AEC & SMEPA.

[332] *See also* TDU Systems, Public Service Co. of CO.

[333] *E.g.,* NARUC, AZ Com, CT DPUC, OK Com, FL Com, NC Com, NM Com.

[334] *E.g.,* Com Ed, Citizens Utilities, PacifiCorp.

[335] *E,g,,* Allegheny Power, PacifiCorp, MidAmerican, PECO, Public Service Co. of CO, Com Ed, NARUC, NRRI, MN DPS, ND Com, FL Com.

[336] *E.g.,* Allegheny Power.

[337] *E.g.,* CCEM, ABATE.

that we believe are more appropriately considered when the Commission reviews unbundled retail transmission tariffs that may come before us in the context of a state retail wheeling program. The Commission therefore reaffirms its decision to require the unbundling only of wholesale transmission from generation.[338]

c. Transmission Provider

1. Taking Service Under the Tariff

In the NOPR, we explained that a public utility must take transmission services for all of its new wholesale sales and purchases of energy under the same tariff of general applicability under which others take service.[339]

Comments

A number of commenters argue that utilities should be required to take all of the transmission for their own use under their tariff.[340] CCEM asserts that a transmission owner should have to schedule, at arm's length, its retail transmission uses and pay posted rates into a separate account; otherwise the capacity might be overforecast at no cost.

PECO requests that the Commission clarify that the requirement that a transmission provider take service under its own transmission tariffs does not apply to: (1) Retail service, (2) existing wholesale contracts, and (3) pooling arrangements. UNITIL claims that the requirement for a transmission provider to take service under its own tariff and to post its own tariff rate should not apply to pool transactions where a single pool-wide rate is applied.

A number of IOUs contend that it is not necessary for the transmission provider to take service under the network tariff because both the transmission provider and the network customers cannot use the tariff to make off-system sales. LILCO states that it is appropriate to distinguish between a transmission owner's use of its transmission system to make: (1) Wholesale bulk power sales; and (2) off-system purchases to serve its native load retail customers. LILCO contends that in the second situation it should not be required to take transmission service under its own open access tariffs.

EGA argues that transmission owners should be required to take transmission service under open access tariffs for both wholesale off-system sales and purchases. It maintains that, as retail competition increases, utilities will eventually have to take retail service under their own tariffs. Power Marketing Association believes that comparability can be achieved only if transmission service provided in connection with coordination transactions is unbundled and the transmission provider takes such transmission service under its tariff.

Consumers Power also claims that there is an inconsistency between the NOPR text, the tariffs, and the proposed regulatory language regarding whether the requirement for a utility to take service under its own tariff applies only to new wholesale transactions.

Commission Conclusion

We conclude that public utilities must take all transmission services for wholesale sales under new requirements contracts and new coordination contracts under the same tariff used by others (eligible customers).[341] For sales and purchases under existing bilateral economy energy coordination agreements, we will give an extension until December 31, 1996, for public utilities to take transmission service under the same tariff used by others.[342] As further discussed in Section IV.F., we will also give an extension of time to December 31, 1996, for certain existing power pooling and other multi-lateral coordination agreements to comply with this requirement. This will ensure that utilities live by their own rules for wholesale transactions and that we can achieve non-discriminatory open access transmission. In the case of a public utility buying or selling at wholesale, the public utility must take service under the same tariff under which other wholesale sellers and buyers take service.

2. Accounting Treatment

In the NOPR, we did not address any accounting aspects of our proposed rule.

Comments

IOUs generally object to a requirement that they pay themselves for their use of the transmission system.[343] NEPCO claims that it is a general principle of accounting that an enterprise cannot recognize and record revenues to itself. NEPCO suggests that, to ensure that utilities' financial statements are not misleading, this aspect of functional unbundling can and should be accomplished through the ratemaking process, rather than by requiring utilities to actually charge themselves revenues for taking transmission services.[344]

Atlantic City Electric states that the added costs of properly administering and accounting for these transactions separately will increase prices to ultimate consumers. It contends that ensuring that operators do not give undue preference to transactions of the transmission provider makes it unnecessary for a utility to charge itself.

CSW argues that some of the provisions of the tariffs were specifically designed for third parties and do not make sense as applied to the transmission provider (*e.g.*, signing service agreements and running credit checks).[345]

Most IOUs suggest that a revenue credit mechanism be used to account for a transmission provider's use of its system. Florida Power Corp states that revenue credits should be equal to the utility's posted rates for transmission service multiplied by the amount of capacity reserved and/or energy transmitted by the utility.

Otter Tail proposes a revenue credit that allocates revenues based on use under the tariff of the utility's transmission investment and credits these revenues against the firm load customers' accounts.

Duke asserts that the transmission provider should maintain records reflecting transmission for its own transactions under the tariff and develop appropriate revenue credits for transmission rates. It also believes that all firm users of the transmission system should receive credits for all non-firm uses.

Allegheny Power states that the crediting of non-firm revenues to network customers would have to be done on an after-the-fact basis when their loads would be known. However, it believes that revenue crediting should occur only if the firm service customer has retained the utility to remarket the customer's unused capacity.

Cajun proposes that all transmission revenues in excess of those implicitly included in the development of the transmission rates, including those that the utility has charged itself, be credited

[338] *But see* discussion of buy/sell transactions in Section IV.I.

[339] FERC Stats. & Regs. ¶ 32,514 at 33,080.

[340] *E.g.*, Michigan Systems, Cleveland, Municipal Energy Agency Nebraska, Missouri Basin MPA, TAPS, Wisconsin Municipals, LG&E, NIEP, CCEM.

[341] With the exception of certain contracts and agreements executed on or before 60 days after publication of the Final Rule in the Federal Register, the regulation we are adopting requires that public utilities take service under their open access tariff for wholesale sales or purchases of electric energy and unbundled retail sales of electric energy, effective on the date the public utility engages in such transactions.

[342] As discussed in Section IV.F., the Commission will not impose this requirement on existing bilateral non-economy coordination agreements, but persons may file complaints that such agreements need to be modified.

[343] *E.g.*, EEI, Con Ed, VEPCO.

[344] *See also* NEPCO.

[345] *See also* Florida Power Corp.

back to the network service transmission customers on a load ratio share basis. If transmission service rates are formula rates that are recalculated annually, Cajun proposes that excess transmission revenues be used to offset the recalculated revenue requirement. If the rates are not formula rates, Cajun states that an explicit tracker with monthly crediting to the network customer must be used.

To avoid cross-subsidization between affiliates and third parties, NRECA suggests that transmission revenues ''paid'' by a utility's generation function to its transmission function be credited back to the utility's nonaffiliated customers, and that any rate discounts extended to the generation function by the transmission function be filed with the Commission with a full explanation of why the discount was extended together with a showing that the discount was made available to all other similarly situated customers.

APPA contends that the Commission's current system of revenue crediting could give transmission owners an unfair competitive advantage by allowing them to use the revenue credit to subsidize the price at which they sell power. It argues that transmission owners should pay the actual price of transmission rather than booking a revenue credit as an offset to the cost of transmission service.

TAPS and Wisconsin Municipals argue that an essential element of true comparability is the ongoing pass-through to network customers of a load ratio share of transmission revenues generated by third-party and the transmission provider's off-system uses of the transmission system.

Houston L&P suggests that the revenue crediting mechanism proposed in the NOPR could be established to recognize the utility's transmission service revenue and expenses in non-third-party wheeling transactions by reclassifying a portion of its revenue equal to the cost of transmission services provided to itself during such transactions. This mechanism would not reclassify expense accounts, but would distinguish that transmission portion of the total transaction's revenue that was associated with covering the cost of transmission service, using the rates charged in similar third-party transactions.

PacifiCorp contends that the Commission should enforce the requirement that utilities account for revenues they pay themselves through the commission's audit powers and through complaint proceedings. It specifically recommends that each transmitting utility be required to indicate, in its Form No. 1 under Account 456, the megawatts and revenues associated with its firm and non-firm off-system sales.[346]

MT Com states that the embedded costs that the Commission functionalizes for jurisdictional purposes should be carefully reconciled with plant balances used to calculate other costs of service.

CCEM wants each transmission provider to charge and book revenues into separate accounts for (1) service provided to itself and off-system sales and third-party sales under the tariffs, (2) impact study costs that the provider performs for itself or an affiliate, and (3) ancillary service revenues, net of out-of-pocket expenses the transmission owner provides itself or an affiliate.

Arizona Public Service recommends that any revenue crediting or booking be prospective only and that enforcement occur through the Commission's periodic audits and a utility's rate cases.

Many IOUs argue that there should be no obligation to credit non-firm transmission revenues to customers who are not using their firm capacity.[347] PacifiCorp contends that all non-firm revenues should be credited against total annual revenue requirements, resulting in lower rates to all customers. Wisconsin P&L maintains that non-firm sales revenue should be shared with all network customers.

Otter Tail argues that non-firm transactions between existing utilities to support and achieve real-time system optimization should be permitted without charge to the transmission owner. CSW asserts that no credits should be made for the non-firm secondary service under the point-to-point tariff and that off-system purchases for native load should not result in a revenue credit.

Southwestern suggests that the Commission not require the crediting of a transmission component associated with off-system purchases by the public utility. Southwestern argues that a credit would interfere with a utility's ability to buy the most economic energy for its native load customers. It also argues that requiring a credit is not comparable to what network customers pay. NEPCO points out that crediting transmission associated with purchases would require native load customers to pay the costs of the utility's purchasing off-system power while network customers do not have to pay a separate point-to-point charge for their off-system purchases. Southwestern claims that the crediting requirement would double-charge the transmitting utility and its native load customers because a utility's off-system purchases directly relate to the load it serves, and that load already is reflected in the transmission rate calculation. Southwestern also claims that it is unclear from the NOPR whether the Commission considers sales from the renewal of existing wholesale requirements contracts as being subject to crediting. It argues that transmission related to these sales should not be subject to the crediting requirement because this is service to native load customers.

Brazos opposes imputing revenues associated with a utility's own use of its transmission system because this will artificially increase the cost of power and deny consumers the benefits of economy energy sales made at market-based prices.

Commission Conclusion

While we used the word ''accounting'' in the NOPR, the real issue is assuring that utilities bear the costs associated with their own uses of the system in a manner comparable to how they charge others. Accordingly, this is a rate issue, not an accounting issue. However, we direct utilities to account for all uses of the transmission system and to demonstrate that all customers (including the transmission provider's native load) bear the cost responsibility associated with their respective uses.[348]

D. Ancillary Services

In the NOPR, the Commission stated that several ancillary services are needed to provide basic transmission service to a customer. These services range from actions taken to effect the transaction (such as scheduling and dispatching services) to services that are necessary to maintain the integrity of the transmission system during a transaction (such as load following and reactive power support). Other ancillary services are needed to correct for the effects associated with undertaking a transaction (such as energy imbalance service).

We proposed six ancillary services to be offered in an open access transmission tariff, which we called (1) scheduling and dispatching services, (2) load following service, (3) energy imbalance service, (4) system protection service, (5) reactive power/voltage control service, and (6) loss compensation service. We requested

[346] If the utility is not required to file a Form No. 1, PacifiCorp states that it should be required to file similar information annually.

[347] *E.g.*, Consumers Power, Northern States Power, PacifiCorp, Allegheny Power.

[348] Additional guidance on this subject is in Section IV.G.4.g.(2)(a).

comments on all aspects of ancillary services, including whether the identified ancillary services are appropriately defined, whether other services should be included, and how these services should be supplied.

Commenters identified a number of other services that may be provided as part of interconnected operations. After considering the comments, we conclude that the following six ancillary services must be included in an open access transmission tariff:

(1) Scheduling, System Control and Dispatch Service;

(2) Reactive Supply and Voltage Control from Generation Sources Service;

(3) Regulation and Frequency Response Service;

(4) Energy Imbalance Service;

(5) Operating Reserve—Spinning Reserve Service; and

(6) Operating Reserve—Supplemental Reserve Service.

A description of these services and our reasons for designating them as ancillary services are included in section 1 below. We also discuss in that section our rationale for excluding other services from the list of ancillary services that must be included in an open access transmission tariff. In section 2 below, we discuss which of the six ancillary services the transmission provider must provide or offer to provide to transmission customers, and which the transmission customer must purchase from the transmission provider. These requirements are summarized as follows:

(1) Scheduling, System Control and Dispatch Service (Transmission Provider must provide and Transmission Customer must purchase from Transmission Provider);

(2) Reactive Supply and Voltage Control from Generation Sources Service (Transmission Provider must provide and Transmission Customer must purchase from Transmission Provider);

(3) Regulation and Frequency Response Service (Transmission Provider must offer to provide only to Transmission Customer serving load in Transmission Provider's control area and Transmission Customer must acquire, but may do so from Transmission Provider, a third party or self supply);

(4) Energy Imbalance Service (Transmission Provider must offer to provide only to Transmission Customer serving load in Transmission Provider's control area and Transmission Customer must acquire, but may do so from Transmission Provider, a third party or self supply);

(5) Operating Reserve—Spinning Reserve Service (Transmission Provider must offer to provide only to Transmission Customer serving load in Transmission Provider's control area and Transmission Customer must acquire, but may do so from Transmission Provider, a third party or self supply); and

(6) Operating Reserve—Supplemental Reserve Service (Transmission Provider must offer to provide only to Transmission Customer serving load in Transmission Provider's control area and Transmission Customer must acquire, but may do so from Transmission Provider, a third party or self supply).

Our requirement that these six ancillary services be included in an open access transmission tariff does not preclude the transmission provider from offering voluntarily to provide other interconnected operations services to the transmission customer along with the supply of basic transmission service and ancillary services.[349]

1. Definitions and Descriptions

Comments

Commenters generally agree that some ancillary services are needed for transmission of power. Some commenters, however, argue for a different name or description for the ancillary services we proposed in the NOPR. Others argue for a more extensive list of services.

EEI believes that the term ''ancillary'' is a confusing description because the services are integral to providing transmission service. NERC, PSE&G, and others claim that ancillary services are not, as the term ''ancillary'' implies, subordinate or auxiliary to the transmission of power; rather such services are conjunctive and required to allow reliable operation of an electric system. BG&E and others contend that ancillary services should be defined as services for control area operation,[350] and not as services provided by an individual, noncontrol area utility. NERC proposes, and many IOU commenters support, an alternative name for these services, ''Interconnected Operations Services.'' NERC contends that the alternative name better reflects the fact that the services are needed in the broader context of allowing control areas, transmission customers, and other operating entities to operate reliably and equitably.

Some commenters propose a greater number of ancillary services. They argue that the services we proposed can be broken down into more discrete functions. A number of commenters provide rather lengthy lists of possible ancillary services to supplement those identified in the NOPR.[351]

NERC identifies twelve services, which it groups into three broad categories: interchange scheduling services, generation services, and transmission services. NERC's proposed interconnected operations services are:

(a) interchange scheduling services:

(1) System control and dispatch services; and

(2) Accounting;

(b) generation services:

(1) Regulation service;

(2) Energy imbalance service;

(3) Frequency response service;

(4) Backup supply service;

(5) Operating reserve service: spinning reserve and supplemental reserve services;

(6) Real power loss service;

(7) Reactive supply (from generation resources) and voltage control service; and

(8) Restoration service; and

(c) Transmission services:

(1) Facilities use; and

(2) Reactive supply (from transmission resources).

NERC also identifies dynamic scheduling as a unique type of dispatch service that control areas must have responsibility over to ensure reliability.

Houston L&P proposes a substitute list of twenty services. NYPP proposes a substitute list of thirty-eight ''unbundled components for transmission service,'' which include twelve generation-related services and twenty-six operations-related services. Oak Ridge recommends that the Commission consider using seven ancillary services, which closely conform to the six services described in the NOPR.[352] Although Oak Ridge identifies several additional ancillary services, it recommends that these services not be included in the list of services to be required because they cannot be measured or because the cost

[349] Of course, public utilities would have to have a rate schedule on file to provide other jurisdictional interconnected operations services.

[350] A control area is part of an interconnected power system with a common generation control system. It may contain one or several utilities. The operator of the control area is responsible for balancing generation and load and for maintaining reliable system operation.

[351] *E.g.*, Oak Ridge, Houston L&P, Carolina P&L, NYPP.

[352] Oak Ridge originally identified nineteen ancillary services, which included a recommended separation of the six NOPR ancillary services into twelve services and seven additional new services.

of metering and billing outweighs the cost of these services.

Commission Conclusion

We will adopt NERC's recommendations for definitions and descriptions with modifications. Starting with NERC's Interconnected Operations Services, we identify some of these as ancillary services that must be offered with basic transmission service under an open access transmission tariff.[353] The definitions developed by NERC for the individual services reflect the current position of a broad spectrum of experts on the subject of interconnected operations. Adoption of NERC's terminology will provide a more universally accepted set of definitions of services. We will retain the term ''ancillary services,'' which will refer to those interconnected operations services that we will require transmission providers to include in an open access transmission tariff.

The interconnected operations services identified by NERC incorporate all of the ancillary services proposed in the NOPR. We believe, however, that several of the individual services identified by NERC do not warrant classification as unbundled ancillary services due to the small cost involved (*e.g.*, accounting). NERC also has identified services that, while capable of being provided in the context of integrated operations, are more appropriately provided for in a separate service agreement or other contractual arrangement (*e.g.*, dynamic scheduling, loss compensation service). NERC and others have attempted to identify all interconnected operation services that could be provided by a control area. The thoroughness of the comments received on this issue has been invaluable to the Commission's deliberations.

We will require that an open access transmission tariff include the six ancillary services that we have identified as necessary for the transmission provider to offer to transmission customers. These are needed to accomplish transmission service while maintaining reliability within and among control areas affected by the transmission service. Other interconnected operations services, such as loss compensation service, may be provided by the transmission provider or third parties to facilitate a particular transaction or operating arrangement. We will not require other interconnected operations services as part of an open access transmission tariff. If a transmission provider supplies such services voluntarily, they may be added to a customer's service agreement with the transmission provider.

As mentioned, we will adopt NERC's definitions with modifications, and we name and describe the six ancillary services below. After each service name, we list in parenthesis the service name in the NOPR that most closely corresponds to the service defined. In the discussion, we explain whether and how we modified NERC's term.

a. The Six Ancillary Services

(1) Scheduling, System Control and Dispatch Service (in the NOPR: Scheduling and Dispatching Service)

Comments

NERC proposes a System Control and Dispatch Service, which provides for (i) interchange schedule confirmation and implementation with other control areas, including intermediary control areas that are providing transmission service, and (ii) actions to ensure operational security during the interchange transaction. A transmission customer may schedule interchange with another control area operator or with another entity inside another control area; however, the control area operators are responsible for confirming and implementing the interchange into or out of their respective areas on behalf of the transmission customer.

NERC also proposes a separate Accounting Service, which provides for energy accounting and billing services associated with interchange. Accounting Service would be provided by the operator of the control area in which the transmission service takes place.

Commission Conclusion

We adopt ''Scheduling, System Control and Dispatch'' as the name for an ancillary service. It substitutes for the NOPR's Scheduling and Dispatching Service.

The name is NERC's recommendation with two modifications. First, we include the term ''scheduling'' in the name of this service because a control area operator/transmission provider must take on the function of scheduling on behalf of customers. Second, we will not require Accounting as a separate ancillary service. The purpose of separating accounting as a stand-alone service would be to allow customers to take it separately from scheduling and system control. However, we believe that accounting for scheduling, system control and dispatch is not separable from these other functions and that accounting costs are likely to be small. Therefore, accounting does not warrant separate service status. The cost of accounting for these services should be included in the cost of Scheduling, System Control and Dispatch Service.

(2) Reactive Supply and Voltage Control From Generation Sources Service (Formerly Reactive Power/Voltage Control Service)

Comments

A number of commenters explain that reactive power and voltage control service is integrally related to the reliable operation of the transmission system. These commenters also note that reactive power and voltage support must be supplied at the location where it is needed.[354] It cannot be provided by a distant supplier.[355]

NERC indicates that reactive supply is necessary to maintain the proper transmission line voltage for the transaction. NERC states that reactive supply is provided from both generation resources and transmission facilities (*e.g.*, capacitors), and lists its provision as two services, distinguished by the facilities that supply them.[356] NERC further distinguishes reactive supply service based on the source of the need for the service: (1) Reactive supply needed to support the voltage of the transmission system and (2) reactive supply needed to correct for the reactive portion of the customer's load at the delivery point.

Commission Conclusion

We adopt ''Reactive Supply and Voltage Control from Generation Sources'' as the name for an ancillary service. It substitutes for the NOPR's Reactive Power/Voltage Control Service.

We accept NERC's identification of two ways of supplying reactive power and controlling voltage. One is to install facilities, usually capacitors, as part of the transmission system. We will consider the cost of these facilities as part of the cost of basic transmission service. Providing reactive power and voltage control in this way is not a separate ancillary service.

The second is to use generating facilities to supply reactive power and voltage control. This use is the service

[353] NERC indicates that the list of services is a work in progress and therefore may not be a complete list. NERC has formed an independent Interconnected Operations Services Working Group (Working Group). The Working Group includes representatives with a broad range of industry interests (transmission-dependent, partial requirements, IPP, transmission-owning, public power). We encourage this effort and will consider future changes to the list of ancillary services or their descriptions to reflect the further development of concepts in this area.

[354] *See, e.g.*, APPA.

[355] *E.g.*, EEI, NERC, NYSEG, FPL, NSP.

[356] *See also* APPA.

named here, which must be unbundled from basic transmission service.

We note, however, that customers have the ability to reduce (but not eliminate completely) the reactive supply and voltage control needs and costs that their transactions impose on the transmission provider's system. For example, customers who control generating units equipped with automatic voltage control equipment can use those units to respond to local voltage requirements and thereby reduce a portion of the reactive power requirements associated with their transaction.[357]

In addition, transmission customers that serve loads can minimize the reactive power demands that they impose on the transmission system by maintaining a high power factor at their delivery points. A poor power factor at a customer's delivery point creates a need for either transmission reactive facilities (*i.e.*, capacitors) or local generator-supplied voltage support.[358]

However, these transmission customer actions do not eliminate entirely the need for generator-supplied reactive power. The transmission provider must provide at least some reactive power from generation sources. For this reason, and because a transmission customer has the ability to affect the amount of reactive supply required, we will require that reactive supply and voltage control service be offered as a discrete service, and to the extent feasible, charged for on the basis of the amount required.[359]

(3) Regulation and Frequency Response Service (in the NOPR: Load Following Service)

Comments

Someone must supply extra generating capacity, called regulating margin, to follow the moment-to-moment variations in the load located in a control area. Following load variations is necessary to maintain scheduled interconnection frequency at sixty cycles per second (60 Hz).

NERC and others support the need for someone to provide load following service to have generation follow a transmission customer's load changes; someone must supply power to meet any difference between a customer's actual and scheduled generation. Usually, the control area operator provides this service, but it is possible for a customer to arrange for someone else to follow its variations in load.

Many commenters indicate that the industry commonly refers to this service as ''Regulation Service.'' [360]

Also, NERC proposes that Frequency Response Service be identified as a related but distinct service. NERC indicates that all control areas are expected to have generation and control equipment to respond automatically to frequency deviations in their networks.

Commission Conclusion

We adopt ''Regulation and Frequency Response'' as the name of an ancillary service. It substitutes for the NOPR's Load Following Service. This name conforms to the terminology recommended by NERC.

We conclude that Regulation Service and Frequency Response Service are the same services that make up the Load Following Service referenced in the NOPR. While the services provided by Regulation Service and Frequency Response Service are different, they are complementary services that are made available using the same equipment. For this reason, we believe that Frequency Response Service and Regulation Service should not be offered separately, but should be offered as part of one service.

(4) Energy Imbalance Service (the Same in the NOPR)

Comments

Many commenters explain that Energy Imbalance Service, as proposed in the NOPR, is necessary when transmission service is provided in a control area that contains the load being served.[361] Energy Imbalance Service supplies any hourly mismatch between a transmission customer's energy supply and the load being serving in the control area. That is, this service makes up for any net mismatch over an hour between the scheduled delivery of energy and the actual load that the energy serves in the control area. In contrast, Regulation and Frequency Response Service corrects for instantaneous variations between the customer's resources and load, even if over an hour these variations even out and require no net energy to be supplied.

Commission Conclusion

We will adopt ''Energy Imbalance'' as the name for an ancillary service. This is the same name proposed in the NOPR. NERC's description is the same as the service proposed in the NOPR.

(5) Operating Reserve—Spinning Reserve Service and

(6) Operating Reserve—Supplemental Reserve Service (in the NOPR These Two Were Formerly System Protection Service)

Comments

Many commenters express confusion regarding the NOPR term ''system protection.'' They indicate that the term ''system protection,'' is described in the NOPR as furnishing operating reserve, but has another meaning in the industry.[362]

Operating reserve is extra generation available to serve load in case there is an unplanned event such as loss of generation. Generation held for operating reserve should be located near the load, typically in the same control area. Operating reserve amounts are set by the region, subregion, or a reserve sharing group in which the transmission customer's load is electrically located.

NERC and other commenters recommend the commonly-used name, ''operating reserve,'' for this service. NERC also indicates that there are two types of operating reserve: spinning reserve and supplemental reserve.

Spinning reserve is provided by generating units that are on-line and loaded at less than maximum output. They are available to serve load *immediately* in an unexpected contingency, such as an unplanned outage of a generating unit.

Supplemental reserve is also generating capacity that can be used to respond to contingency situations. Supplemental reserve, however, is not available instantaneously, but rather within a short period (usually ten

[357] The ability to reduce reactive power requirements will be affected by the location and operating capabilities of the generator. Any arrangement for the customer to self-supply a portion of reactive supply should be specified in the transmission customer's service agreement with the transmission provider.

[358] Transmission providers may propose delivery point power factor standards, including additional (penalty) charges for failure to maintain specified power factors, in service agreements with customers. We will evaluate the reasonableness of any such proposals by public utilities to determine whether they conform to prudent utility practices and are comparable to requirements imposed by the utility on other customers, including the utility's own requirements customers, and are otherwise just and reasonable.

[359] Separation of reactive supply and voltage control from basic transmission service also may contribute to the development of a competitive market for such service if technology or industry changes result in improved ability to measure the reactive power needs of individual transmission customers or the ability to supply reactive supply from more distant sources. We recognize that these capabilities may not be fully developed at present and the ability to distinguish the reactive power needs of individual customers may be limited at first to generator control and power factor correction.

[360] *E.g.*, NERC, EEI, Florida Power Corp.

[361] *E.g.*, NERC, EEI.

[362] *E.g.*, EEI, Florida Power Corp, TVA, Wollenberg.

minutes). Supplemental operating reserve is provided by generating units that are on-line but unloaded, by quick-start generation, and by customer-interrupted load, *i.e.*, curtailing load by negotiated agreement with a customer to correct an imbalance between generation and load rather than increasing generation output.

Commission Conclusion

We adopt Operating Reserve—Spinning Reserve Service and Operating Reserve—Supplemental Reserve Service as the names of two related, but distinct, ancillary services. They substitute for a single ancillary service in the NOPR, System Protection Service. The names conform to the terminology recommended by NERC. We distinguish them because these services may be subject to different reliability requirements; the resources that supply each service may not be the same; and the two services may be provided by different suppliers.

b. Other Services Discussed in the NOPR

Commenters discussed whether two other services that were discussed in the NOPR should be designated as ancillary services.[363] Although we do not designate these as ancillary services for purposes of this Rule, we discuss the names and descriptions here so that we can discuss our policy regarding these services.

(1) Real Power Loss Service (in the NOPR: Loss Compensation Service)

In the NOPR, we proposed that Loss Compensation be an ancillary service.

Comments

NERC recommends the term, ''Real Power Loss,'' to refer to energy consumed in transmission, much of it by resistance heating of the lines and transformers. Many parties, including NERC, comment that there are a number of ways to compensate the transmission provider for the losses that occur in providing transmission service. They indicate that real power loss service can be obtained from a variety of sources, such as the power supplier, the customer, a third-party, the transmission provider, or another control area. Also, the loss is commonly accounted for by a transmission customer receiving less energy at the point of delivery than it provides to the transmission provider at the point of receipt. The difference between delivered and received energy can be set equal to the energy lost in transmission.

Commission Conclusion

We adopt the term ''Real Power Loss'' as the name of this interconnected operations service. It substitutes for the Loss Compensation service described in the NOPR. This name conforms to the terminology recommended by NERC.

Although proposed as an ancillary service in the NOPR, we will not require that Real Power Loss be included as an ancillary service in an open access transmission tariff. It is not necessary to require the transmission provider to supply energy losses to the transmission to ensure comparable transmission access. Real Power Loss is more appropriately an interconnected operations service that transmission providers may offer voluntarily to provide to transmission customers.

It is not necessary for the transmission provider to supply Real Power Loss to effect a transmission service transaction. The transmission provider is not uniquely situated to provide Real Power Loss service to its customers, nor does it have a comparative advantage over anyone in providing such a service. Indeed, to require the transmission provider to provide this service would effectively obligate the transmission provider to engage in a sale of power when such a sale is not needed to effect the transmission service transaction.

As noted in the comments, customers have several options to cover losses that occur when electricity moves across transmission facilities.[364] The availability of open access permits the customer to obtain energy losses from many regional suppliers.

Although we will not require the transmission provider to supply Real Power Loss to the transmission customer nor require the customer to purchase it from the transmission provider, the customer must make provision for Real Power Loss. It cannot take basic transmission service without such a provision. A customer seeking transmission service must bring to the transaction sufficient energy and capacity to replace the losses associated with its intended transaction.[365] Consequently, we will require that the transmission customer's service agreement with the transmission provider identify the party responsible for supplying real power loss. In addition, we will require that the transmission provider indicate, either in its tariff or on its OASIS, what the energy and capacity loss factors would be for any transmission service it may provide so that potential customers will know the amount of losses to replace.

(2) Dynamic Scheduling (the Same in the NOPR)

In the NOPR's discussion of Scheduling and Dispatch Service, we pointed out that dynamic scheduling is possible in some regions. We asked for comments on whether we should require dynamic scheduling as an ancillary service, given the complexity of the service.

Comments

Most commenters would not have us require Dynamic Scheduling as an ancillary service.[366] Dynamic scheduling provides the metering, telemetering, computer software, hardware, communications, engineering, and administration required to allow remote generators to follow closely the moment-to-moment variations of a local load. In effect, dynamic scheduling electronically moves load out of the control area in which it is physically located and into another control area.

Commission Conclusion

We adopt the name Dynamic Scheduling Service, but we will not designate it as an ancillary service that must be included in an open access transmission tariff.

In the NOPR, we noted that Dynamic Scheduling could be used in a transmission transaction if it is technically feasible to do so without adversely affecting reliability. We did not propose in the NOPR that Dynamic Scheduling be named an ancillary service. Although Dynamic Scheduling is closely related to Scheduling, System Control and Dispatch Service, it is a special service that is used only infrequently in the industry. It uses advanced technology and requires a great level of coordination. Each Dynamic Scheduling application has unique costs for special telemetry and control equipment, making it difficult to post a standard price for the service.

Consequently, we will not require that the transmission provider offer Dynamic Scheduling Service to a transmission customer, although it may do so voluntarily. If the customer wants to

[363] In addition, NERC designates ''facilities use service'' as an interconnected operations service. We note that the facilities use service described by NERC is simply basic transmission service, which must be provided under an open access tariff. We do not consider facilities use service to be an ancillary service.

[364] *See, e.g.*, Portland, APPA, PacifiCorp, EEI.

[365] If a transmission provider does not charge for transmission used to supply losses for its own wholesale power sales and purchases, it may not charge others. If it charges others, it must charge for its own uses.

[366] *E.g.*, Detroit Edison, El Paso, FPL, Minnesota P&L, NIPSCO.

purchase this service from a third party, the transmission provider should make a good faith effort to accommodate the necessary arrangements between the customer and the third party for metering and communication facilities.

c. Other Services Not Discussed in the NOPR

Comments

Some commenters identified several other services that were not discussed in the NOPR, which they recommend we require to be provided as ancillary services.[367] Examples are emergency power, supplemental power, and inadvertent power.

Commission Conclusion

We believe that these other services generally refer to either (1) generation services that are not related to providing transmission or (2) a subpart of a service discussed above, the cost of which is not easily separable from the other service. Consequently, we will not name any of these services as an ancillary service that a transmission provider will be required to offer separately under an open access transmission tariff. However, generation-related services may be offered voluntarily to the transmission customer.

We discuss below two of these proposed generation-related ancillary services, which NERC included among its proposed interconnected operations services.

(i) Backup Supply Service

Comments

NERC explains that Backup Supply is electric generating capacity and energy that is provided to the transmission customer as needed (1) to replace the loss of its generation sources and (2) to cover that portion of the customer's load that exceeds its generation supply for more than a short time. NERC notes that Backup Supply Service is a long-term service, which distinguishes it from Operating Reserve Service and Energy Imbalance Service. Backup Supply service replaces temporary use of operating reserves; it serves load after operating reserves are returned to standby mode to maintain operating reserves at required levels. Backup Supply may last for hours, weeks, or longer. NERC indicates that a transmission customer could reduce its need for backup supply service by using interruptible load control or active demand-side management control, or both.

Commission Conclusion

We accept the term ''Backup Supply'' as the name for this interconnected operations service, but we will not require this service as an ancillary service under an open access transmission tariff. Backup Supply Service is not required for comparable open access transmission service.

Backup Supply Service is an alternative source of generation that a customer can use in the event its primary generation source becomes unavailable for more than a few minutes. Although we believe that the two short-term operating reserve services (spinning and supplemental) are necessary to support transmission, we conclude that long-term service is not necessary. Backup Supply is a generation service that may reasonably be viewed as the responsibility of the transmission customer, who may contract for backup service or curtail load.

We will impose no obligation on the transmission provider to provide power to the customer for a time longer than specified in the tariff for the customer's own backup power supply to be made available. The transmission provider is obligated to protect against emergencies for a short time; it has no obligation to furnish replacement power on a long-term basis if the customer loses its source of supply. The transmission provider has no obligation to provide power for the weeks necessary for unit maintenance, for example.

The transmission provider is not uniquely situated to provide Backup Supply Service to its transmission customers, nor does it have a comparative advantage over others in providing such service. Moreover, as Backup Supply Service may require substantial amounts of generation capability, it is inappropriate to require the transmission provider to assume significant generation responsibilities as we functionally unbundle transmission from generation.

Although the transmission provider will not be required to offer this service to transmission customers, it may offer voluntarily to provide Backup Supply Service to its transmission customers. Any arrangements for the supply of such service by the transmission provider should be specified in the customer's service agreement.

(ii) Restoration Service

Comments

NERC states that Restoration Service provides facilities and procedures to enable (1) a transmission provider to restore its system and (2) a transmission customer to start its generating units or restore its loads if local power is unavailable. Other commenters refer to Restoration Service as Blackstart Service, which may be provided by the operator of the host control area, another control area operator, or another generation supplier.[368]

According to NERC, close coordination with the host control area operator is absolutely necessary during system restoration operations. Under current industry practice, each control area operator is responsible for implementing a restoration plan in coordination with non-control area utilities as well other power producers. Many large generating units require startup power to restart after being out of service. Startup power may be provided, for example, by self-contained diesel engine generator sets located at a generating plant. If electric power is not available from the grid, some and perhaps many plants must obtain the necessary power from their auxiliary generators to restart plants and return the grid voltage to the proper level. Other generators without blackstart capability may rely on power from the grid to restart, once the grid is energized by others. NERC notes, however, that it may be inappropriate to rely completely on power from the grid for restart power because power from the grid may be unavailable or insufficient. Consequently, at least some power plants must have internal auxiliary power sources.

Commission Conclusion

We accept the term ''Restoration'' as the name for this interconnected operations service. We will not require the transmission provider to offer Restoration Service as a separate ancillary service in an open access transmission tariff.

Comments on Restoration Service appear to describe two services, blackstart service and planning for system restoration. Presumably, each utility and power producer will do its part through voluntary coordination and self-interest to ensure a reliable and adequate source of startup power for its generating units. We will not require a transmission provider to provide blackstart capability to transmission customers. Generators without blackstart capability can instead purchase blackstart power from any power supplier connected to the grid at an appropriate power price, if such service is available after a contingency is corrected.

[367] *E.g.,* NERC, Carolina P&L, Oak Ridge, Houston L&P.

[368] *E.g.,* Atlantic City, Oak Ridge.

The obligation to plan for restoration capability is a system control area function that rests with the transmission provider and the operator of the control area in which the transmission provider is located. The transmission provider (or its associated control area operator) generally makes arrangements with enough generators to provide the system with this capability at strategic locations on the transmission system. Thus, restoration planning is intrinsic to the transmission provider's basic transmission service and included in its cost.

2. Obligations of Transmission Providers and Transmission Customers With Respect to Ancillary Services

In the NOPR, the Commission proposed that public utilities required to file open access transmission tariffs also be required to provide unbundled ancillary services to transmission customers. Although the NOPR included a list of ancillary services to be offered by transmission providers, the NOPR did not indicate whether a customer must take basic transmission service from the transmission provider to be eligible to require the transmission provider to supply ancillary services. Comments on these issues are summarized below.[369]

Comments

Several commenters[370] distinguish generation-related ancillary services from others. Generation-related services are those that require the provider to have extra generating capacity or to provide electric energy. The remaining ancillary services are called transmission-related services or control area services. Transmission-related services would involve, for example, voltage support from transmission facilities. An example of a control area service is system control and dispatch. Commenters do not agree on how each service should be classified.

Many commenters state that only control area operators should be allowed to offer certain ancillary services, such as scheduling, system control and dispatch.[371] They believe that otherwise reliability might suffer.

Minnesota P&L states that certain ancillary services (*e.g.* reactive power from generators, load following, frequency control) should be provided exclusively by the operator of the control area where the load resides.[372] Minnesota P&L indicates that obtaining these services externally could jeopardize reliability. Several commenters claim that a control area operator must provide the scheduling, system control and dispatch service and reactive power supply service (except in cases where the customer's load is very close to the generating source).[373] Numerous commenters indicate that load following (now called Regulation and Frequency Response Service) generally is provided only by a control area operator.[374]

EEI and other commenters state that energy imbalance service must be provided by either the control area operator or some other entity that is in the control area where the customer's load is located and has real-time response capability.[375] NYSEG points out that transmission providers generally are also control area operators and thus automatically provide energy imbalance service to maintain interchange flows and control area reliability. For this reason, NYSEG believes it is important that this service remain a responsibility of the transmission provider.

SC Public Service Authority contends that ancillary services can be provided only by an entity large enough to operate at a NERC regional scale. It states that ancillary services protocols must be established regionally to support regional transmission services.

Other commenters disagree. They argue that all the generation-related ancillary services identified in the NOPR can be obtained from sources other than the transmission provider.[376] American Wind believes the ability of a transmission customer to self-supply ancillary services or purchase them from a third party will help to curb inflated prices for such services. Southwest TDU Group also claims that permitting entities outside the transmission provider's control area to provide ancillary services will enhance competition and reduce the need for Commission oversight of charges for ancillary services.

A majority of commenters support the view that the transmission-providing public utility should provide ancillary services. Many commenters do not discuss the services individually but present their views generally on the provision of ancillary services. Missouri-Kansas Industrials and CCEM support a requirement that utilities make ancillary services available through a tariff. They argue that, from a customer's point-of-view, it is extremely critical that a transmission provider be required to furnish these services under a regulated, nondiscriminatory, cost-based tariff format. NIEP argues that, until a fully competitive market for ancillary services develops, transmitting utilities should be obligated to provide or arrange for any and all of the NOPR ancillary services, to the extent that the transmission customer desires such services. Direct Service Industries emphasizes that a transmission provider should be required to provide any ancillary service that it is capable of supplying. Direct Service Industries and Utilities For Improved Transition claim that open access tariffs should state clearly that the transmission provider must secure ancillary services for a transmission customer if the transmission provider is not able to provide these services itself. Large Public Power Council contends that, during the transition to a competitive market for generation-related ancillary services, transmission providers should be required to provide all ancillary services related to generation that existing customers now take on a bundled basis. OH Com notes that transmission owners, by virtue of their position as transmission owners, are necessarily the providers of last resort for certain ancillary services. OH Com therefore believes that only transmission providers should provide ancillary services.

Several non-IOU, transmission-owning commenters, however, urge that the Commission not require transmission providers to provide ancillary services that they cannot physically supply, *i.e.*, if they lack sufficient generation, lack control area facilities, or have slow-responding generating units.[377] NRECA and TDU Systems also state that many cooperatives and transmission

[369] Some commenters suggest that transmission providers be required to provide, or transmission customers be required to purchase or self-supply, certain services other than the six ancillary services that we will require to be included in an open access transmission tariff. Because we will not require the transmission provider to offer any services other than basic transmission service and the six ancillary services, comments on requirements to provide or take other services are not included in the summary.

[370] *E.g.*, NERC, Tallahassee, IL Com.

[371] *E.g.*, BG&E, Minnesota P&L, Florida Power Corp.

[372] *See also* Florida Power Corp and Montana Power.

[373] *E.g.*, Carolina P&L, Texas Utilities, NERC, PSE&G.

[374] *E.g.*, SCE&G, Montana Power, NIPSCO, EEI, PacifiCorp. EEI and PacifiCorp indicate that dynamic scheduling of load following service is an exception to the general practice of the control area operator providing load following service.

[375] *E.g.*, Montana Power, TDU Systems.

[376] *E.g.*, Tallahassee, Wisconsin Municipals, IL Com.

[377] *E.g.*, OVEC, OG&E, Memphis, Nebraska Public Power, TDU Systems, TANC, San Francisco, Brazos.

dependent systems presently obtain ancillary services from control area utilities under specific contract terms. Consequently, if their member systems are asked to provide transmission service, they may not be able to take on the obligation to secure ancillary services under their existing contracts for transmission customers. Soyland and Pacific Northwest Coop argue that a transmission provider should not be required to supply services that it does not provide to its native load.

Most IOU commenters and others oppose a requirement that the transmission provider be obligated to provide generation-related ancillary services. They offer the following reasons: (1) The need for such services differs from one transaction to the next; (2) a transmission provider is neither uniquely qualified to provide these services, nor is it essential that such provider be the one providing these services in order to effect a transaction; (3) until it is demonstrated that these services cannot be obtained from a source other than the transmission provider, it is inappropriate to require transmission providers to supply such services; and (4) a transmission provider should have no residual obligation as a provider of last resort to plan its system to have generating resources available for the supply of ancillary services.[378] IL Com also contends that utilities should not be required to provide generation-related ancillary services under general transmission service tariffs if such services can be obtained from the bulk power market.

Other IOU commenters argue that there is a fundamental inconsistency between an obligation to provide or obtain ancillary services for customers and the NOPR's unbundling requirement. For example, BG&E claims that it is inconsistent to require the traditional vertically integrated utility to functionally unbundle and also to remain responsible for providing at cost-based rates what should be competitively-priced generation services. Florida P&L and other IOU commenters argue that providing generation-related ancillary services effectively imposes the load-serving obligation of the transmission customer on the transmission provider.

However, some IOU commenters contend that the transmission provider or its agent should be required to provide certain ancillary services.[379] NIPSCO and PacifiCorp believe that load following (now called Regulation and Frequency Response Service) should be provided only by the transmitting utility, especially if the customer's load and resources are located in the control area operated by the transmitting utility. EEI contends that a third-party generator should have the opportunity to provide regulation service if it resides in the transmission provider's control area and coordinates its actions with the control area operator.

IN Com and NY Com recommend that the Commission provide flexibility in assessing responsibility for the supply of ancillary services. MN DPS recommends that an individual transmission provider should not be required to file an individual tariff for ancillary services if it is a member of an RTG whose tariffs adequately cover the same services.

EEI contends that a control area utility should not be required to provide ancillary services to a third party outside its control area. EEI also argues that, if the transmission provider is not a control area, it should not be required to procure ancillary services from a control area on behalf of a third party seeking service over its system. Rather, the third party should be responsible for procuring the ancillary services it needs. Other IOU commenters argue that the responsibility to acquire ancillary services belongs to the transmission customer, not the transmission provider.[380]

Many IOU commenters express concern that ancillary services be offered and taken on a symmetrical basis, *i.e.*, if transmission providers are uniquely situated to provide the service, customers should likewise be required to take and pay for the service from such transmission providers.[381] BG&E claims that it is patently unfair to give third-party users the option not to purchase ancillary services that the transmission provider must offer. BG&E argues that, if transmission providers have an obligation to provide ancillary services, equity dictates that transmission customers have a corresponding obligation to take those services or compensate transmission providers for the costs associated with the unused capabilities. United Illuminating argues that the requirement to provide service without a corresponding obligation to purchase service unfairly burdens the transmission provider and skews competition in favor of transmission customers.

Other non-IOU commenters oppose a symmetric obligation to provide and purchase particular ancillary services.[382] Ontario Hydro and others claim that the customer should decide on a case-by-case basis which ancillary services it needs to purchase.

BPA and BG&E assert that transmission providers should be able to require that the party *receiving* the power, which may not be the transmission customer, be responsible for acquiring ancillary services. This would allow the transmission provider to establish the appropriate contractual arrangements with the party that is actually receiving the energy and avoid shifting responsibility to a party that is merely arranging the transmission service.

A number of IOU commenters express concern that customers may ''lean'' on a transmission provider's system for ancillary services. That is, they worry that the transmission customer may not purchase an ancillary service but nevertheless rely on the transmission provider to provide it. Commenters propose various remedies to address this concern. NIEP, Dayton P&L and others argue that the Commission should require that, as a prerequisite to basic transmission service, the transmission customer has either arranged to obtain ancillary services from the transmission provider or has demonstrated it has an arrangement with an alternative supplier that is reliable and sufficient to satisfy the ancillary service needs associated with the transmission service transaction. NYPP believes that, if the customer's method of providing ancillary services does not meet the standards of the transmission provider, the transmission provider should be able to require that the transmission customer find another ancillary service supplier or purchase the service directly from the transmission provider at its tariff rates.[383] EEI proposes that penalties be permitted as a backstop if the market cannot resolve the ''leaning'' problem. VEPCO suggests that utilities should have the option to require customers to maintain backup supply reserves.

Commission Conclusion

The NOPR proposed that six ancillary services be included in an open access transmission tariff. Some commenters interpret the NOPR to require that transmission providers make a ''universal'' offer of unbundled ancillary

[378] *E.g.*, PSNM, Atlantic City, Centerior, UWG, Texas Utilities, Entergy, LG&E, Montana Power, FPL, United Illuminating, Large Public Power Council, Christensen.

[379] *E.g.*, NIPSCO, PacifiCorp, Orange & Rockland, Allegheny, NYSEG, EEI.

[380] *E.g.*, BG&E.

[381] *E.g.*, CSW, BG&E, ConEd, United Illuminating, Ohio Edison, Atlantic City, Centerior, SoCal Edison, Duke, EEI.

[382] *E.g.*, RUS, TDU Systems, DE Muni.

[383] *See also* NYSEG, Ohio Edison.

services, *i.e.*, an offer to any transmission customer regardless of location and whether the transmission customer would also be taking basic transmission service from the supplier of ancillary services.[384] Such interpretation is incorrect; it goes beyond what is required for comparability. These services are required to be provided only to customers taking basic transmission service. However, transmission providers may offer these services on a voluntary basis to other customers if technology permits.

Transmission *through* or *out of* a control area requires fewer ancillary services from the operator of the control area than transmission *within* or *into* a control area to serve loads in the control area. If the requested transmission service transaction involves more than one control area, *i.e.*, the receipt point and delivery point of transmission service are located in different control areas, certain ancillary services will be needed only in the control area where the transmission customer's load is located.

We will distinguish two groups or categories of ancillary services: (1) Services that we will require the transmission provider to provide to all its basic transmission customers, and (2) services that we will require the transmission provider to offer to provide only to transmission customers serving load in the provider's control area. The first group is comprised of (i) Scheduling, System Control and Dispatch and (ii) Reactive Supply and Voltage Control from Generation Services. The second group is comprised of (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental.

With respect to the first group of ancillary services, we conclude that the transmission provider that operates a control area is uniquely positioned to provide these services. Thus, as stated above, we will require the transmission provider that operates a control area to *provide* these ancillary services. We will also require that the transmission customer purchase these services from the transmission provider, as explained in the next section.

With respect to the second group of ancillary services, we conclude that the transmission provider is not always uniquely positioned to provide these services, although in many cases it may be the only practical source. Thus, we will require the transmission provider to *offer* to provide the ancillary services in the second group to transmission customers serving load in the transmission provider's control area. We also will require the transmission customer serving load in the transmission provider's area to acquire these services, but it may do so from the transmission provider, a third party or self-supply. These ancillary services must be provided by someone if the system is to be operated reliably; the customer may not decline the transmission provider's offer of ancillary services unless it demonstrates that it has acquired the services from another source. The transmission provider may require the customer to decide which of these ancillary services it will purchase from the transmission provider when it applies for basic transmission service.

If the transmission provider is a public utility providing basic transmission service but is not a control area operator, it may be unable to provide some or all of the ancillary services we require without substantial investment. In this case, we will allow the transmission provider to fulfill its obligation to provide, or offer to provide, ancillary services by acting as the customer's agent. We will require the transmission provider to offer to act as agent for the transmission customer to secure these services from the control area operator.[385] The customer may have the transmission provider act as agent or may secure the ancillary services directly from the control area operator. As stated above, the customer may also secure the second group of ancillary service from a third party or by self-supply.

If the transmission provider is a public utility that is not a control area operator, but its control area operator is a public utility, the control area operator must offer to provide all ancillary services to any transmission customer that takes transmission service over facilities in its control area whether or not the control area operator owns or controls the facilities used to provide the basic transmission service.[386]

We discuss the requirement to supply and purchase each ancillary service individually below.

a. Ancillary Services Required To Be Provided by Transmission Provider for All of Its Transmission Customers

(1) Scheduling, System Control and Dispatch Service

We conclude that this service is necessary to the provision of basic transmission service within every control area. As NERC and other commenters point out, Scheduling, System Control and Dispatch Service can be provided only by the operator of the control area in which the transmission facilities used are located.[387] This is because the service is to schedule the movement of power through, out of, within, or into the control area.

(2) Reactive Supply and Voltage Control Service From Generation Sources

We conclude that this service is necessary to the provision of basic transmission service within every control area. Because reactive power cannot be transmitted for significant distances, the local transmission provider has to supply reactive power from generation sources. It is often uniquely situated to supply reactive power. The transmission provider or the operator of the control area in which the provider is located cannot avoid supplying it to the transmission customer, and the transmission customer cannot avoid taking at least some of this service from the transmission provider. Although a customer is required to take this ancillary service from the transmission provider or control area operator, it may reduce the charge for this service to the extent it can reduce its requirement for reactive power supply.

b. Ancillary Services Required To Be Offered Only to Transmission Customers Serving Loads in the Transmission Provider's Control Area

(1) Regulation and Frequency Response

Regulation and Frequency Response Service is not required for transmission out of or through the transmission provider's control area. We conclude that this service must be offered only for transmission within or into the transmission provider's control area to serve load in the area. Customers may be able to satisfy the regulation service obligation by providing generation with

[384] *E.g.*, PSNM, Atlantic City, Centerior, Texas Utilities, Entergy, FPL, Utility Working Group.

[385] The requirement to offer to act as agent is in lieu of the requirement for the transmission provider to supply the ancillary service to the transmission customer. Many commenters asked that we not require the transmission provider to acquire the capacity to provide ancillary services that it does not provide for itself but acquires from its control area operator. *E.g.*, EEI, NRECA, BPA, TDU Systems.

[386] If the transmission provider is a control area operator but not a public utility, we can order transmission services only upon application, pursuant to section 211 and 212 of the FPA. However, the provision of transmission services by non-public utilities would be necessary to satisfy the reciprocity condition in public utilities' open access transmission tariffs.

[387] *E.g.*, Carolina P&L, Texas Utilities, PSE&G.

automatic generation control capabilities to the control area in which the load resides. Dynamic scheduling may also be used to electronically ''move'' a remote generating unit into the appropriate control area. For customers to take advantage of these developments, a transmission provider is required to identify the regulating margin requirements for transmission customers serving loads in its control area and develop procedures by which customers can avoid or reduce such requirements.

(2) Energy Imbalance

We conclude that Energy Imbalance service must be offered for transmission within and into the transmission provider's control area to serve load in the area.

Energy imbalance represents the deviation between the scheduled and actual delivery of energy to a load in the local control area over a single hour. A transmission customer can reduce or eliminate the need for energy imbalance service in several ways. A customer can avoid taking energy imbalance service if it controls generation with load-following capabilities located in the control area. The Final Rule pro forma tariff allows unlimited changes before the hour at no additional charge to a customer's hourly schedule of energy deliveries to the control area. By changing its schedule more frequently (based on updated load information, for example), a customer can reduce or avoid energy imbalance charges. Other customer options to reduce or avoid energy imbalance charges include (i) establishing the load as a separate control area island within the transmission provider's control area with its own generation and load and (ii) removing the customer's load from the transmission provider's control area through dynamic scheduling.[388]

(3) Operating Reserve—Spinning

(4) Operating Reserve—Supplemental

We conclude that Operating Reserve—Spinning and Operating Reserve—Supplemental must be offered for transmission within and into the transmission provider's control area to serve load in the control area. Reserves should be located near load in case of unplanned unavailability of generating units serving load in the control area. We will permit transmission providers to rely upon prevailing regional practices to set reserve criteria. Transmission providers are required to facilitate efforts by customers to meet Operating Reserve obligations with their own generating resources or from third-party sources if they can satisfy the regional criteria.

If a customer uses either type of operating reserve, it must expeditiously replace the reserve with backup power to reestablish required minimum reserve levels.

3. Unbundling and Bundling Ancillary Services

a. Services That Can Be Bundled With Transmission Service

In the NOPR, the Commission proposed that transmission providers should be required to offer ancillary services as discrete services, unbundled from basic transmission service.

Comments

While most commenters support the approach to unbundling the ancillary services proposed in the NOPR, a number of commenters argue that, for technical and administrative reasons, certain services should be bundled with basic transmission service. For example, some commenters assert that Reactive Supply and Voltage Support service should be bundled with basic transmission service.[389] They argue that this service is integrally related to the operation of the transmission system, that it must be provided at or near the point of need, and that its costs are difficult to isolate and account for.[390] Other commenters argue that scheduling and dispatch service, for similar reasons, should be bundled with basic transmission service.[391]

A few commenters suggest that other services could be bundled with the basic transmission service. For example, NYSEG identifies energy imbalance service as a candidate for bundling. EEI identifies frequency regulation and NYMEX identifies frequency control as services that could be bundled with basic transmission service.

Some commenters believe that the Commission should allow utilities to file transmission tariffs that bundle all necessary transmission and ancillary services, at least as an interim measure.[392]

On the other hand, other commenters believe that a greater level of unbundling of transmission and ancillary services is necessary to facilitate the development of competitive markets and to ensure that transmission customers are able to purchase only the services they require.[393] Dayton P&L believes that all ancillary services should be offered as discrete services with separate prices. Texas Utilities asserts that generation-related ancillary services should be unbundled and separately priced.

Commission Conclusion

Although commenters raise valid concerns, they do not provide a compelling reason to require that our six ancillary services be bundled with basic transmission service. We have, however, changed the proposal in the NOPR to clarify that reactive supply and voltage support from *transmission* resources is part of basic transmission service.

Unbundling ancillary services will promote competition and efficiency in their supply. Because most generation-based ancillary services potentially can be provided by many of the generators connected to the transmission system, some customers may be able to provide or procure such services more economically than the transmission provider can. Once they are unbundled, a more competitive market may emerge to supply such services.

Also, unbundling makes possible a more equitable distribution of costs. Because customers that take similar amounts of transmission service may require different amounts of some ancillary services, bundling these services with basic transmission service would result in some customers having to take and pay for more or less of an ancillary service than they use. For these reasons, the Commission concludes that the six required ancillary services should not be bundled with basic transmission service.

With respect to the specific question of whether Reactive Supply and Voltage Control from Generation Sources should be bundled with basic transmission service, we believe that this service should remain unbundled because, as explained above, transmission customers have some ability to effect how much of this service they need and a third party may be able to supply some portion of a customer's reactive power requirements.

b. Services That May Be Offered and Sold as a Package

The NOPR indicated that ancillary services must be offered separately from one another but did not indicate if the

[388] Some of these options (*e.g.*, establishing a separate control area), while technically feasible, may be too costly or otherwise inadvisable.

[389] *E.g.*, Carolina P&L, NYSEG, FPL, NSP, WP&L, Orange & Rockland, Arizona, Salt River, SC Public Service Authority, Brazos, NY Com.

[390] *See, e.g.*, Carolina P&L Initial Comments at 56.

[391] *See, e.g.*, CCEM, Carolina P&L, NYSEG, CINergy.

[392] *E.g.*, UT Com, Washington and Oregon Energy Offices, WA Com.

[393] *E.g.*, Direct Service Industries, Mt. Hope Hydro.

transmission provider may also offer a package of ancillary services.

Comments

Several commenters support giving customers the option either to purchase ancillary services as separate and distinct services or to purchase a package of services from the transmission provider.[394] Others, such as Tallahassee, recommend that utilities be prohibited from bundling the purchase of one service with another so that a transmission customer cannot rely on the transmission provider for just one or a few of the ancillary services.

EEI and ELCON argue that the Commission should permit customers the option to request that transmission providers offer packages of selected ancillary services.[395] They and other commenters express a concern that efficiencies can be lost under a policy that precludes combining ancillary services.

Commission Conclusion

We conclude that a transmission provider must offer and price the individual ancillary services separately. It may not tie the purchase of one to the purchase of another.

However, we will allow a transmission provider to assemble packages of ancillary services (*not* bundled with basic transmission service) that can be offered at rates that are less than the total of individual charges for the services if purchased separately. It may also offer rate discounts on any ancillary service. If a rate discount is offered to the transmission owner itself or to an affiliate of the transmission owner, the same discount must be offered to non-affiliates, as well. In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory. All discounts must be posted on the transmission provider's OASIS.

4. Reassignment of Ancillary Services

In the NOPR, the Commission noted that ancillary services may not be suitable for reassignment and requested comments on this issue.

Comments

Commenters express divided views on the reassignment issue. Some IOU commenters believe that, subject to technical limitations, ancillary services could be reassigned.[396] Other commenters, including many IOUs, oppose reassignment because they believe it is impractical.[397] In particular, PacifiCorp claims that the customer-specific nature of generation-related ancillary services prevents such services from being reassigned.

TDU Systems argue that transmission customers that must pay for ancillary services they do not need should be able to resell them to someone else.[398] Mt. Hope Hydro claims that, if a bulk power transaction and the associated transmission service can be reassigned, it is reasonable that the ancillary services used to support the transaction also should be reassigned, particularly if the same facilities and contract path are used.[399]

Commission Conclusion

We conclude that transmission customers will be allowed to reassign ancillary services along with the reassignment of basic transmission service. The Commission believes that a policy of transmission capacity reassignment may not be possible unless the ancillary services used to support the transmission are also reassignable.

5. Pricing of Ancillary Services

In the NOPR, we asked for comments on ancillary service pricing and proposed specific ancillary services prices in the Stage One implementation rates. Many commenters commented on the Stage One rates. There is no Stage One in the Final Rule.

Comments

Many commenters state that ancillary services are difficult to price. They suggest diverse pricing approaches. IN Com notes that, because utilities and regulatory commissions have no experience with pricing unbundled ancillary services, the process needs to evolve but the goal should be to encourage market pricing in competitive markets. Air Liquide believes the best pricing policy should be negotiated bilateral agreements, provided market power is mitigated.

Other commenters express concern about how pricing proposed in the NOPR would affect the development and operation of competitive ancillary services markets. Industrial Energy Applications notes that low price caps on generation-related services, such as supplying losses, imbalance energy, operating reserve and backup power, which can be provided from many sources, inhibit competitive market development. There is little incentive for other providers to invest in facilities to provide these services. Dayton P&L and others contend that the Commission should not require transmission providers to provide generation-based ancillary services at cost-based rates and then allow third parties to resell such services at market-based rates. PacifiCorp expresses concern that the NOPR's pricing proposal would be overly restrictive in the emerging competitive market for generation-related ancillary services.

Many commenters argue that cost-based price caps are appropriate for ancillary services if there are no alternative suppliers or until competitive markets develop.[400] CAMU suggests that the comparability standard is not met if market rates exceed the costs of providing ancillary services. Allegheny, Ohio Edison and Atlantic City support cost-based pricing for Reactive Power/Voltage Control. Ohio Edison recommends cost-based pricing for frequency regulation, and Atlantic City recommends it for scheduling and dispatch.

Several commenters suggest that the Commission require cost-based rates for ancillary services where no source other than the transmission provider exists and market-based rates for generation-related ancillary services if competition exists.[401] Washington and Oregon Energy Offices recommend that, before permitting market-based rates, at least two other non-affiliated parties should be able to offer a nearly identical ancillary service and that the Commission should use the same standards for allowing market-based rates for ancillary services that it has used for wholesale power sales. Mt. Hope Hydro argues that vertically integrated utilities should be permitted to charge cost-based rates that are limited to no more than the market price for ancillary services. It also contends that companies whose generation facilities are not supported by captive retail or transmission customers should be authorized to sell at market-based prices.

The vast majority of commenters from all interest groups who address market-based pricing for ancillary services agree that market-based pricing is appropriate for ancillary services where competitive market conditions exist. However, commenters disagree over whether a

[394] *E.g.*, Direct Service Industries, Mt. Hope Hydro, ELCON, PA Com.

[395] EEI Initial Comments at V–4; ELCON Initial Comments at 21.

[396] *E.g.*, WP&L, NYSEG.

[397] *E.g.*, Consumers, PacifiCorp, Carolina P&L, PSNM, Salt River, PA Com, TDU Systems.

[398] TDU Systems Initial Comments at 87.

[399] Mt. Hope Hydro Initial Comments at 17.

[400] *E.g.*, Utilities For Improved Transition, Idaho, CINergy, Direct Service Industries, Mt. Hope Hydro, ABATE, TDU Systems, Missouri-Kansas Industrials, Washington and Oregon Energy Offices, IN Com.

[401] *E.g.*, PJM, Texas Utilities, Entergy, Carolina P&L.

competitive market for ancillary services currently exists.

In determining the extent of competition, many commenters distinguish between ancillary services that are (1) generation-related and (2) transmission-related. Commenters disagree over whether the Commission can declare generation-related ancillary services to be competitive on a generic basis. Many commenters contend that transmission-related ancillary services are not available in a competitive market; consequently, they agree that prices for such services should be cost-based.

Commission Conclusion

We will consider ancillary services rate proposals on a case-by-case basis.

In response to comments,[402] we offer here some general guidance on ancillary services pricing principles.

(1) Ancillary service rates should be unbundled from the transmission provider's rates for basic transmission service, even though such services are a necessary adjunct to basic transmission service.

(2) The fact that we have authorized a utility to sell wholesale power at market-based rates does not mean we have authorized the utility to sell ancillary services at market-based rates.

(3) In the absence of a demonstration that the seller does not have market power in such services, rates for ancillary services should be cost-based and established as price caps, from which transmission providers may offer a discount to reflect cost variations or to match rates available from any third party. If a rate discount is offered to the transmission owner itself or to an affiliate of the transmission owner, the same discounted rate must be offered to non-affiliates, as well. In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory. All discounts must be posted on the transmission provider's OASIS.

(4) The amount of each ancillary service that the customer must purchase, self-supply, or otherwise procure must be readily determined from the transmission provider's tariff and comparable to the obligations to which the transmission provider itself is subject. The provider must take ancillary services for its own wholesale transmission under its own tariff.

(5) The location and characteristics of a customer's loads and generation resources may affect significantly the level of ancillary service costs incurred by the transmission provider. Ancillary service rates and billing units should reflect these customer characteristics to the extent practicable.

6. Accounting for Ancillary Services

Comments

Some commenters suggest that there may be a need for revising the Uniform System of Accounts to track better the costs of providing discrete ancillary services. Other commenters believe that ancillary services are transmission-type services and suggested that the costs of generation-provided ancillary services be refunctionalized from power production expense to transmission expense.

Oak Ridge asserts that a primary goal of those interested in restructuring the electricity industry should be to identify clearly the different functions that are today buried within the vertically integrated utility and bundled into one price. Oak Ridge, however, indicates that achieving this ideal of identifying unbundled services at appropriate prices will be difficult because of utility accounting practices.

EEI asserts that since the current Uniform System of Accounts was designed to track costs incurred to provide bundled wholesale service, it does not track the discrete costs incurred to provide ancillary services. Therefore, according to EEI, a major update is needed to support the pricing of discrete ancillary services.

ConEd states that ancillary services are integral and essential elements of providing transmission services. It notes that, historically, due to the vertical integration of utilities, those services have been bundled with the other services provided and the costs associated with providing ancillary services have not been specifically defined. ConEd claims that to a large degree, this is due to the fact that utility accounting mechanisms were not established with the intention of identifying the costs for ancillary services.

UI asserts that if transmission customers are to be charged for certain ancillary services, it may be necessary to refunctionalize certain specific costs items from generation to transmission. UI points out that some of the reactive power to support system voltages and to provide transmission services, for example, is supplied from the variable reactive output of the generators. It states that these costs, to the extent they can be identified with the provision of transmission service, should be refunctionalized to the transmission account. However, UI states it may not be possible to develop a unit cost for specific transactions. Thus, UI states it may be more appropriate to roll these costs into the embedded transmission rate and allocate them among the various users of the transmission system.

Commission Conclusion

To ensure comparable transmission access a Transmission Provider is obligated to offer or arrange to provide certain ancillary services to the Transmission Customer. Also, the Transmission Provider may offer to provide other ancillary services to the Transmission Customer. A Transmission Customer is obligated to purchase certain ancillary services from the Transmission Provider.

Generation resources provide certain ancillary services, while transmission resources provide other ancillary services. Consequently, the costs of providing certain ancillary services are recorded in the utility's power production expense accounts, while others are recorded in the utility's transmission expense accounts.

Currently, the Uniform System of Accounts requires that costs incurred in providing ancillary services be recorded as power production or transmission expense depending upon which resource the utility uses to supply the service. At this time, we are not convinced that the amounts involved or the difficulty associated with measuring the cost of ancillary services warrants a departure from our present accounting requirements. We will specify, however, that revenues a Transmission Provider receives from providing ancillary services must be recorded by type of service in Account 447, Sales for Resale, or Account 456, Other Electric Revenues, as appropriate.

E. Real-Time Information Networks

In the Open Access NOPR, the Commission determined that in order to remedy undue discrimination, a utility must functionally unbundle its wholesale services, and that among the things required by functional unbundling is that the utility, when buying or selling power, rely upon the same electronic network that its transmission customers rely upon to obtain transmission information. Accordingly, the Commission accompanied its issuance of the Open Access NOPR with issuance of a notice of technical conference that initiated a proceeding in Docket No. RM95–9–000

[402] Many commenters were particularly concerned that rates for energy losses, a NOPR ancillary service, should be market-based. We need not address this concern in this Rule, however, because we will not require Real Power Losses to be offered as an ancillary service.

to consider whether Real-Time Information Networks (RINS) or some other option would be the best means to ensure that potential customers of transmission services have access to the information necessary to obtain open access transmission service on a non-discriminatory basis.[403]

The Commission affirms its conclusion that in order to remedy undue discrimination in the provision of transmission services it is necessary to have non-discriminatory access to transmission information, and that an electronic information system and standards of conduct are necessary to meet this objective. Therefore, we issue, in conjunction with this Final Rule, a final rule adding a new Part 37 that requires the creation of a basic OASIS and standards of conduct.[404]

The Phase I OASIS rules require each public utility (or its agent), as defined in section 201(e) of the Federal Power Act, 16 U.S.C. 824(e), that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to develop and/or participate in an OASIS. The Phase I OASIS rules describe what information must be provided on the OASIS during Phase I and how OASIS must be implemented.

In addition, the new Part 37 contains a code of conduct applicable to all transmission providing public utilities. The code of conduct is designed to ensure that preferential access to information about wholesale transmission prices and availability is not available to employees of the public utility engaged in wholesale marketing functions or to employees of certain of the public utility's affiliates.

F. Coordination Arrangements: Power Pools, Public Utility Holding Companies, Bilateral Coordination Arrangements, and Independent System Operators

Comments

Timing of Reformation

Many marketers, IPPs, and other nonmembers of pools request that the Commission immediately apply unbundling and transmission tariff requirements to all new transactions under existing pooling agreements. APPA states that the Commission should not deal with power pools as a ''follow-on activity'' because treatment of pools is an integral step in achieving transmission comparability. AEC contends that until pools publish open access tariffs, the Commission should permit applications for section 211 transmission orders from one or more applicants directed to multiple respondents.

Existing pools generally urge the Commission to allow time for the pools to propose alternative structures or agreements which would meet the objectives of the final rule. EEI states that the rule may create problems for power pools that will not be examined or understood by the Commission and the public until the Commission's pooling inquiry is completed; it requests that the pooling inquiry be completed before a final rule is issued. Duke recommends that implementation of open access transmission services by power pools be addressed in a separate proceeding because implementation of open access for power pools raises complex issues.

EGA, among others, argues that new transactions under existing pooling agreements should not be grandfathered, but rather should be required to meet the functional unbundling requirements of the final rule. Some pool members argue that pool transactions are largely not wholesale transactions. For example, PECO (a member of PJM) requests the Commission to clarify that the delivery of pooled generation to pool members' native load is not a ''wholesale purchase'' of power and thus would not require taking transmission service under one's own open access transmission tariff. Another member of PJM, BG&E, interprets the proposed rule to require all PJM economy trades to be firm point-to-point services; it claims that such a requirement ''jeopardizes the continued viability of the pool.''

System-Wide Tariffs

Virtually all commenters on power pool issues state that the tariff requirements should not be applied directly to individual utilities who are members of ''tight'' power pools. ELCON, CCEM, and others argue that the pro forma tariff requirement should be applied directly to ''tight'' or ''single system'' power pools to avoid discriminatory ''pancaking'' of transmission rates. However, Duke argues that where there are both multiple owners and operators, as in ''loose'' pools, it is appropriate to have individual tariffs unless the pool members agree otherwise. DOE recommends a power pool file a single pool-wide tariff to offset problems associated with joint ownership or control of transmission. CT DPUC recommends that the Commission provide guidance for transmission access and pricing (so as to avoid needless disruption of present methods).

Flexible Treatment

Most commenters on power pools support recognizing regional differences among power pools and urge flexibility. PSE&G (a member of PJM) states that open access tariffs must be specially crafted to deal with power pool members. NYPP and PJM state that they are considering innovations and urge that their efforts not be stifled by any final rule. CSW proposes a region-wide pricing model based on power flows. NPPD, a member of the Mid-Continent Area Power Pool (MAPP), says MAPP is considering adopting the megawatt-mile approach to transmission pricing. SoCal Edison states that California utilities are developing a market-based power pool and that it is crucial for the final rule to be flexible to permit innovations throughout the country.

ELCON and power marketers, however, argue for uniformity and point out the difficulties of moving power from system to system where each system has varying standards or ''pool rules.'' These commenters support uniform application of the terms and conditions in the pro forma tariffs to create a national standard.

NEPOOL emphasizes that since pools remain voluntary, the imposition of rules that are not acceptable to pool members simply increases the likelihood that members will withdraw and pools will disintegrate. For this reason, NEPOOL states that solutions to enhance competition (within a tight pool setting) are best identified through the consensus of pool members, which requires both time and flexibility on the part of the Commission.

DE, DC, NJ and MD Coms emphasizes its concern that a one-size-fits-all open-access policy, while perhaps benefiting subsets of individual suppliers and purchasers, may not be the best solution for the millions of retail customers who currently rely on power pools.[405] It wants the Commission to be aware that the individual commissions have begun a formal dialog among each other and with the PJM utilities to discuss possible regional solutions to transitional competitive issues.

Open Membership

NIEP and CCEM argue that the competitive playing field cannot be level unless nonmembers receive certain

[403] *See* Real-Time Information Networks, Notice of Technical Conference and Request for Comments, 60 FR 17726 (April 7, 1995).

[404] In Phase II, we will continue to develop the requirements for fully functional OASIS. We expect to issue a final rule on Phase II OASIS requirements sometime in 1997.

[405] *E.g.*, DE Com, DC Com, NJ Com, MD Com.

power pool services on terms comparable to those for pool members. Members of pools state that ''return in kind'' transactions are efficient, but that such transactions are not appropriate for those entities that are not similarly situated to vertically integrated utilities.

EEI maintains that those seeking the benefits of pool membership must accept the burdens imposed on existing pool members (otherwise, they would have an advantage, not comparability). EEI believes that new pool participants can negotiate and ''buy into'' the pool resources. Many commenters claim that unbundling certain power pool services to accommodate open access will solve the problem.

MidAmerican states that if the Commission grants nonmembers access to pool transmission service, the Commission should allow a period of at least four years for pools to restructure and refile rate schedules to avoid the inequitable results which the Commission's requirements will impose on pool members.

MidAmerican contends that the Commission should authorize pool members to unilaterally withdraw from their pools if any restructuring or revision of rate schedules is unacceptable to the member.

Holding Companies

Allegheny, Southern, and other holding companies argue that coordination agreements among subsidiaries of a utility holding company system do not constitute a power pool and should not be subject to any obligations the Commission may place on power pools.

Bilateral Coordination Agreements

Ohio Edison requests clarification that the Commission is not requiring new wholesale coordination transactions to be under the open access tariffs; they may be continued under existing coordination agreements. It stresses the importance of such agreements in making economy and emergency transactions.

A number of commenters agree that existing coordination contracts should not be abrogated or modified, and that transactions under these existing contracts should *not* be governed by the provisions of the pro forma tariffs.[406] These commenters generally argue that existing coordination agreements should not be abrogated or amended by the final rule because: (1) They were not negotiated in the environment envisioned by the NOPR; (2) coordination sales are beneficial to consumers and ratepayers (and thus it would not be in the public interest to curtail them); and (3) the termination of coordination agreements, which in some cases have been in place for years and are tailored to parties' peculiar circumstances, could cause severe hardships in certain regions (especially with regard to scheduling and curtailment).

PSNM contends that such agreements are the result of mutually beneficial bargaining. LPPC and MEAG argue that current contracts negotiated among parties provide cost savings to consumers, which may be foregone if existing contracts are modified. Central Louisiana suggests that the pro forma tariff provisions should be flexible enough to achieve comparability if applied to both existing and new coordination agreements.

Some commenters argue that there may be cases where it is inappropriate to modify existing coordination agreements to satisfy the requirements of the rule. They assert that coordination agreements providing for emergency transactions,[407] reliability,[408] and resource efficiency gains[409] need special attention. However, Soyland believes that existing agreements need to be reviewed if there is substantial increase in wholesale power market transactions, at the customer's option. TDU Systems argues that coordination contracts supporting system reliability should be honored and given scheduling and curtailment preference. TDU Systems contends that any amendments should be at the parties' discretion rather than by Commission mandate.

Several commenters suggest that the proposed rule is unclear about whether only existing transactions under agreements already approved by the Commission will be exempt from functional unbundling, or whether the proposed rule also would exempt (or grandfather) *new* transactions entered into pursuant to existing approved contracts.[410] Other commenters recommend that the Commission clarify that its policy on unbundling applies to all new transactions, whether pursuant to new or existing agreements.[411] ConEd and KCPL request clarification that purchases made to satisfy retail service are not subject to the requirements of the pro forma tariffs.

CCEM argues that all coordination transactions, including new transactions under existing agreements, should be unbundled to ensure that transmission providers are implementing the posted transmission rate. CINergy contends that the comparability standard should be applied to existing coordination agreements, including buy-resell agreements, to mitigate any unfair bulk power market advantages. Functional unbundling would ensure that a utility includes an EBB-posted transmission rate in the transaction charge. CINergy and Power Marketing Association recommend that the Commission use its authority under section 206 to require all utilities to file amendments to their existing coordination agreements providing for transmission service to be taken pursuant to the parties' open access transmission tariffs. Power Marketing Association further recommends that the Commission establish expedited procedures to address the situation arising from conflicting pro forma tariffs and existing coordination provisions.

Tallahassee also believes that the comparability standard should be applied to existing coordination agreements, but Tallahassee recommends that the Commission establish a transition period to allow for renegotiation among parties rather than imposing modifications to existing agreements. Renegotiation would provide an opportunity to retain previously bargained-for benefits. Detroit Edison also contends that many of the existing coordination agreements do not provide for the services required under the pro forma tariffs. Like Tallahassee, Detroit Edison recommends that the Commission allow sufficient time for parties to renegotiate existing agreements. CINergy suggests a three-year transition period.

Coordination Pricing Practices

EEI and PJM disagree with the Commission's assertion that current coordination pricing is no longer just and reasonable in the absence of an open access tariff. Ohio Edison and PA Com question the basis of the Commission's preliminary conclusion that current coordination pricing is no longer justified in the absence of a seller's tariff offer of non-discriminatory open access transmission services. PA Com asserts that the Commission's underlying assumption of general lack of transmission access by wholesale customers has not been established as fact in the proposed rule.

[406] *E.g.*, Central Louisiana, Dayton P&L, LPPC, MEAG, Missouri Basin Group, Montana-Dakota Utilities, Nebraska Public Power District, Ohio Edison, PSNM.

[407] *E.g.*, Arizona, Ohio Edison.

[408] *E.g.*, Soyland, NRECA.

[409] *E.g.*, APPA.

[410] *E.g.*, APPA, CCEM, EGA.

[411] *E.g.*, APPA, CCEM, LG&E, EGA.

MN DPS supports current coordination pricing methods provided that utilities have executed open-access tariffs. Missouri Basin Group argues that, if increased market competition materializes through open access, utilities will decreasingly rely on current coordination pricing if it no longer produces the most beneficial outcome. Missouri Basin Group recommends the Commission simply allow utilities to choose a pricing method even if a utility opts for a less beneficial outcome. Nebraska Public Power District also urges the Commission to avoid mandating coordination pricing methods. Nebraska Public Power District is concerned that this may impede establishing RTGs where such pricing is by mutual agreement and subject to ADR procedures.

Several commenters agree that current coordination pricing may no longer be appropriate in an open access regime.[412] FL Com believes that current coordination pricing should be replaced by market-based rates if open access transmission service is imposed by the Commission.

Commission Conclusion

The term ''coordination'' is applied to a wide variety of wholesale power sales agreements within the industry, including interchange, interconnection, pooling, and other agreements. Broadly speaking, any non-requirements power sales agreement can be considered to be a coordination agreement.[413]

The Final Rule's general requirement for non-discriminatory transmission access and pricing by public utilities, and its specific requirement that public utilities unbundle their transmission rates and take transmission service under their own tariffs, apply to all public utilities' wholesale sales and purchases of electric energy, including coordination transactions. The Commission has determined that certain existing wholesale coordination arrangements and agreements must be modified to ensure that necessary transmission services for such arrangements and agreements are taken under open access transmission tariffs and thus that such arrangements and agreements are not unduly discriminatory. Below we discuss how and when various types of coordination agreements will need to be modified, and when public utility parties to coordination agreements must begin to trade power under those agreements using transmission service obtained under the same open access transmission tariff available to non-parties.

Coordination arrangements, and the agreements governing them, vary widely. They range from relatively simple bilateral arrangements to complex tight power pools. Our discussion addresses four broad categories of arrangements and accompanying agreements: ''tight'' power pools, ''loose'' power pools, public utility holding company arrangements, and bilateral coordination arrangements. For purposes of implementing the non-discriminatory, open access requirements of the Final Rule, we are dividing bilateral coordination agreements into two general categories: bilateral economy energy agreements and other bilateral coordination agreements. Economy energy agreements typically provide for short-term economy trading ''if, as, and when available'' and are generally driven by the buyer and seller's generation costs. They do not require either the seller or the buyer to engage in a particular transaction. Other coordination agreements are typically longer term or open-ended. Some may involve joint ownership or joint planning of generation.[414] Others may provide joint operation of facilities so that the parties can coordinate their maintenance schedules or provide one another with emergency service. These longer-term coordination agreements are distinguished from short-term economy trading agreements in that the parties have undertaken a contractual obligation to operate their facilities so as to support one another under the conditions specified in the arrangements.

As noted in the NOPR, power pools, in contrast to most bilateral arrangements, present complex issues that may require special implementation requirements.[415] This is because these arrangements may involve agreements containing an intricate set of rights, obligations, and considerations among the members of a pool. We provide for implementation requirements herein that vary depending upon the type of ''pooling'' arrangement involved.

The Commission has concluded that in order to adequately remedy the undue discrimination in transmission access and pricing by public utilities that are members of power pools or other coordination arrangements, such public utilities must remove preferential transmission access and pricing provisions from agreements governing their transactions. The filing of open access tariffs by the public utility members of a power pool is not enough to cure undue discrimination in transmission if those public utilities can continue to trade with a selective group within a power pool that discriminatorily excludes others from becoming a member and that provides preferential intra-pool transmission rights and rates. The same holds true of certain bilateral arrangements that allow preferential transmission pricing or access. These arrangements and agreements need to be changed. We expect such arrangements and agreements to be modified by the dates indicated in this Rule. However, if necessary, we will institute section 206 proceedings against public utilities that do not make such filings.

The Commission's technical conferences on power pools, ISOs, and pro forma tariffs made clear to us the need to articulate guidance in this Rule on the restructuring or modification of unduly discriminatory coordination arrangements—particularly tight power pools.[416] They also made clear that members of tight power pools, in particular, need time to make the necessary modifications to these arrangements. We recognize that members of some power pools are already in the process of formulating voluntary modifications to pooling agreements to be filed with the Commission (*e.g.*, PJM, NYPP, NEPOOL). Therefore, we will provide adequate time for these filings as well as guidance to changes that need to be made.

In addition, although we do not at this time find it necessary to require power pools to form an independent system operator in order to remedy undue discrimination, we believe ISOs may prove to be an effective means for

[412] *E.g.*, Arizona, CINergy, Consumers Power, EEI, PJM.

[413] For example, a 30-year contract to supply 50 MW of power can be considered to be a coordination arrangement because it is not a contract to meet all of the buyer's power requirements.

[414] Agreements dealing with joint ownership or operation of transmission facilities are discussed at Section IV.C.3.

[415] The Commission did not define what it meant by ''power pools'' in the NOPR discussion. We use the term power pool in a very broad context here and have generally characterized three broad types of arrangements that represent some form of pooling: ''tight pools'', ''loose'' pools and other multilateral coordination arrangements, and holding companies. Even between the categories of tight and loose pools, however, there is no bright dividing line.

[416] A technical conference on pro forma tariffs was held on October 27, 1995. A technical conference on power pools was held on December 5 and 6, 1995 and a follow-up technical conference on ISOs and power pools was held on January 24, 1996.

accomplishing comparable access.[417] We recognize that several utilities are exploring the possibility of forming ISOs. For example, discussions are ongoing in California, PJM, NYPP, and the Midwest. Therefore, because of the industry's interest (which we share) in the concept of an ISO and the potential for an ISO to provide non-discriminatory transmission services to all market participants, we will provide guidance in this section on minimum ISO characteristics.

1. Tight Power Pools

For purposes of this Rule, the tight power pools are: New York Power Pool (NYPP), New England Power Pool (NEPOOL), Pennsylvania-New Jersey-Maryland Interconnection (PJM), and the Michigan Electric Coordinated Systems (MECS).

Public utilities who are members of a tight pool must file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) An individual Final Rule pro forma tariff; or (2) a joint pool-wide Final Rule pro forma tariff. They are not required to take service for *pool transactions* under the tariff that is filed within 60 days. However, they will be required to file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and must begin to take service under that tariff for all pool transactions no later than December 31, 1996. The purpose of this extension is to allow sufficient time for tight pools to amend their pooling agreements and to restructure their operations to conform to the requirements of the Final Rule. We also believe that the additional time is necessary to preserve efficient trading arrangements during the restructuring period.

The Commission therefore will require that the public utility members of tight pools file reformed power pooling agreements no later than December 31, 1996. The reformed power pool agreements should establish open, non-discriminatory membership provisions (including establishment of an ISO, if that is a pool's preferred method of remedying undue discrimination) and modify any provisions that are unduly discriminatory or preferential. The membership provision must allow any bulk power market participant to join, regardless of the type of entity, affiliation, or geographic location.

If the reformed agreement allows members to make transmission commitments or contributions in exchange for the discounted transmission rates, the pool may file a transmission tariff that contains an access fee for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs. Alternatively, the pool could make available a transmission rate that is structured the same as the discounted rate (*e.g.*, non-pancaked) but with a higher rate that is justified on the basis of transmission-related costs borne (or contributed) by the pool members. However, any such access fee or higher rate must be justified solely on the basis of transmission costs and cannot be tied to the costs of any other agreement among the pool members (*e.g.*, generation reserve sharing).

2. Loose Pools

For purposes of the Final Rule, a loose pool is any multi-lateral (more than 2 public utilities) arrangement, many of which contain discounted and/or special transmission arrangements. Examples are MAPP, Inland Power Pool, and the MOKAN pool. Other entities may qualify to be treated as a loose pool if they can show that they meet the definition above.

Public utilities within a loose pool must file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) An individual Final Rule pro forma tariff; or (2) a pool-wide Final Rule pro forma tariff. They are not required to take service for *pool transactions* under the tariff that is filed within 60 days. However, they will be required to file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and must begin to take service under that tariff for all pool transactions no later than December 31, 1996. The purpose of this extension is to allow sufficient time for loose pools to amend their agreements and to restructure their operations to conform to the requirements of the Final Rule. We also believe that the additional time is necessary to preserve efficient trading arrangements during the restructuring period.

The Commission therefore will require that the public utility members of loose pools file reformed power pooling agreements no later than December 31, 1996. They also must file a joint pool-wide tariff no later than December 31, 1996. The reformed power pool agreements should establish open, non-discriminatory membership provisions and modify any provisions that are unduly discriminatory or preferential. The membership provision must allow any bulk power market participant to join, regardless of the type of entity, affiliation, or geographic location.

The Commission recognizes that loose pools typically do not operate as a single control area and that operational unbundling, perhaps through an ISO, might not be readily attainable at this time. Nonetheless, we encourage the members of loose pools to explore the advantages of the ISO concept.

If the reformed agreement allows members to make transmission commitments or contributions in exchange for discounted transmission rates, the pool may file a transmission tariff that contains an access fee for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs. Alternatively, the pool could make available a transmission rate that is structured the same as the discounted rate (*e.g.*, non-pancaked) but with a higher rate that is justified on the basis of transmission-related costs borne (or contributed) by the pool members. However, any such access fee or higher rate must be justified solely on the basis of transmission costs and cannot be tied to the costs of any other agreement among the pool members (*e.g.*, generation reserve sharing).

3. Public Utility Holding Companies

Public utility members of registered and exempt holding companies that are also members of tight or loose pools are subject to the tight and loose pool requirements set forth above. The remaining holding company public utility members, with the exception of the Central and South West (CSW) System, are required to file a single system-wide Final Rule pro forma tariff permitting transmission service across the entire holding company system at a single price within 60 days of publication of the Final Rule in the Federal Register (service companies may, of course, file on behalf of their public utility affiliates). As discussed below, CSW presents special circumstances.

The CSW System is comprised of four operating public utilities. Two of those utilities, Southwestern Electric Power Company (SWEPCO) and Public Service Company of Oklahoma (PSO) operate in the Southwest Power Pool (SPP). The other two, West Texas Utilities Company (West Texas) and Central Power and Light Company (CP&L), operate in the Electric Reliability

[417] The DOJ and DOE suggested that the Commission examine operational unbundling as a way of enforcing comparability in transmission service. DOJ and DOE believe that functional unbundling may not be adequate to ensure comparability and so have recommended that some form of operational unbundling be required. While we believe that requiring this is premature, we note that an ISO is one way to achieve operational unbundling and we encourage the voluntary development of ISOs.

Council of Texas (ERCOT). SWEPCO and PSO exchange power with West Texas and CP&L through two high voltage, direct current interconnections (the North and East Interconnections).[418]

Pursuant to the Commission orders concerning the North and East Interconnections, CP&L, West Texas, SWEPCO, and PSO have on file what are referred to as the ''to or from and over tariffs.'' [419] Those tariffs apply only to transmission service that involves the delivery of power and energy to or from and over the North and East Interconnections.[420] The tariffs do not apply to the transmission of power for CSW subsidiaries other than the operating companies. The tariffs in many respects are different from the Final Rule pro forma tariff and do not provide comparable services. Moreover, the pricing provided in the ''to or from and over'' tariffs is different from the pricing set forth in the Texas Commission's final open access rule.[421]

Given these special circumstances, we believe it appropriate to give CSW the opportunity to propose a solution to achieving comparability for the CSW system. Accordingly, we direct the public utility subsidiaries of CSW to consult with the Texas, Arkansas, Oklahoma and Louisiana Commissions and to file not later than December 31, 1996 a system tariff that will provide comparable service to all wholesale users on the CSW System,[422] regardless of whether they take transmission service wholly within ERCOT or the SPP, or take transmission service between the reliability councils over the North and East Interconnections.[423]

The Commission will give public utilities that are members of holding companies an extension of the requirement to take service under the system tariff *for wholesale trades* between and among the public utility operating companies within the holding company system. This extension is until December 31, 1996—the same extension we are granting to power pools. At that point, the public utility operating companies will be required to take service under the Final Rule pro forma tariff for wholesale trades among themselves. In addition, it may be necessary for registered holding companies to reform their holding company equalization agreement to recognize the non-discriminatory terms and conditions of transmission service required under the Final Rule pro forma tariff.

4. Bilateral Coordination Arrangements

Any bilateral wholesale coordination agreement executed after the effective date of this Rule will be subject to the functional unbundling and open access requirements set forth in this Rule. With regard to existing bilateral agreements, however, the diversity of the types of agreements currently on file presents special implementation problems. The Commission is particularly concerned with future economy energy transactions that may occur pursuant to existing umbrella-type coordination agreements. Accordingly, we shall require all bilateral economy energy coordination contracts executed before the effective date of this Rule to be modified to require unbundling of any economy energy *transaction* occurring after December 31, 1996. All non-economy energy bilateral coordination contracts executed before the effective date of this Rule will be permitted to continue in effect, but will be subject to complaints filed under section 206 of the FPA. Under those procedures, the rates, terms, and conditions of individual coordination contracts may be challenged as unduly discriminatory or otherwise unlawful.

To compute the unbundled coordination compliance rate, the utility must subtract the corresponding transmission unit charge in its open access tariff from the existing coordination rate ceiling. For example, if a utility has a coordination rate ceiling for hourly service of incremental cost plus 15 mills/kWh and a transmission tariff rate for hourly service of 3 mills/kWh, it shall revise the coordination rate ceiling to incremental cost plus 12 mills/kWh. The Commission cautions that the compliance filing will be strictly limited to removing the current transmission tariff price from the coordination price and will not be a medium for otherwise revising the residual coordination sales price.

The transmission rate for the coordination transactions may be at or below the tariff rate. However, if a utility's transmission operator offers a discounted transmission rate to the utility's wholesale marketing department or an affiliate for the purposes of coordination transactions, the same discounted rate must be offered to others for trades with any party to the coordination agreement. In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory.[424] This may require parties to file modifications of the coordination arrangements.

ISO Principles

The Commission recognizes that some utilities are exploring the concept of an Independent System Operator and that the tight power pools are considering restructuring proposals that involve an ISO. While the Commission is not requiring any utility to form an ISO at this time, we wish to encourage the formation of properly-structured ISOs. To this end, we believe it is important to give the industry some guidance on ISOs at this time. Accordingly, we here set out certain principles that will be used in assessing ISO proposals that may be submitted to the Commission in the future.

These principles are applicable only to ISOs that would be control area operators, including any ISO established in the restructuring of power pools. We recognize that some utilities are exploring concepts that do not involve full operational control of the grid. Without in any way prejudging the merits of such arrangements, the following principles do not apply to independent administrators or coordinators that lack operational control. We do not have enough information at this time to offer guidance about such entities, but

[418] The North and East Interconnections were ordered by the Commission pursuant to sections 210, 211 and 212 of the Federal Power Act. *See* Central Power and Light Company, *et al.*, 17 FERC ¶ 61,078 (1981), *order on reh'g*, 18 FERC ¶ 61,100 (1982); 40 FERC ¶ 61,077 (1987).

[419] Houston Lighting and Power Company (HL&P) and Texas Utilities Electric Company (TU) also have on file ''to or from and over tariffs'' pursuant to the Commission orders.

[420] *See, e.g.*, CP&L and West Texas Interpool Transmission Service Tariff, § 4.1.

[421] *Compare* 21 TEX REG 1397, LEXIS, *mimeo* at 18 (adopting hybrid pricing scheme with 70% of transmission rate based on regional postage stamp method and 30% based on the vector-absolute megawatt-mile method) *with Id.* at Article III.

We note that the Texas Commission concluded that the ERCOT portion of the costs of the North and East Interconnections ''should be included in the cost of service, when the owners of the (Interconnections) amend the FERC tariffs for the use of the (Interconnections) to provide equal access to other utilities. 21 TEX REG, LEXIS, *mimeo* at 24.

[422] It may be appropriate to have different rates for transmission service wholly within ERCOT or the SPP, and for service between the reliability councils. However, the same rates, terms, and conditions applicable for third parties should also be applicable to the CSW System's wholesale transmission requirements.

[423] We recognize that this action may require amendment to the Commission's orders under FPA sections 210, 211, and 212, ordering the North and East Interconnections. In this regard, it should be clearly understood that the Commission's action in requiring comparable service by the CSW System is not in any way intended to result in public utility status to any ERCOT participants that are not public utilities—*e.g.*, HL&P and TU. *See* 16 U.S.C. 824(b)(2).

[424] All discounts must be posted on the transmission provider's OASIS.

recognize that they could perform a useful role in a restructured industry.

Because an ISO will be a public utility subject to our jurisdiction,[425] the ISO's operating standards and procedures must be approved by the Commission. In addition, a properly constituted ISO is a means by which public utilities can comply with the Commission's non-discriminatory transmission tariff requirements. The principles for ISOs are:

1. The ISO's governance should be structured in a fair and non-discriminatory manner. The primary purpose of an ISO is to ensure fair and non-discriminatory access to transmission services and ancillary services for all users of the system. As such, an ISO should be independent of any individual market participant or any one class of participants (e.g., transmission owners or end-users). A governance structure that includes fair representation of all types of users of the system would help ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner. The ISO's rules of governance, however, should prevent control, and appearance of control, of decision-making by any class of participants.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards. To be truly independent, an ISO cannot be owned by any market participant. We recognize that transmission owners need to be able to hold the ISO accountable in its fiduciary role, but should not be able to dictate day-to-day operational matters. Employees of the ISO should also be financially independent of market participants. We recognize, however, that a short transition period (we believe 6 months would be adequate) will be needed for employees of a newly formed ISO to sever all ties with former transmission owners and to make appropriate arrangements for pension plans, health programs and so on. In addition, an ISO should not undertake any contractual arrangement with generation or transmission owners or transmission users that is not at arm's length. In order to ensure independence, a strict conflict of interest standard should be adopted and enforced.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner. An ISO should be responsible for ensuring that all users have non-discriminatory access to the transmission system and all services under ISO control. The portion of the transmission grid operated by a single ISO should be as large as possible, consistent with the agreement of market participants, and the ISO should schedule all transmission on the portion of the grid it controls. An ISO should have clear tariffs for services that neither favor nor disfavor any user or class of users.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council. Reliability and security of the transmission system are critical functions for a system operator. As part of this responsibility an ISO should oversee all maintenance of the transmission facilities under its control, including any day-to-day maintenance contracted to be performed by others. An ISO may also have a role with respect to reliability planning. In any case, the ISO should be responsible for ensuring that services (for all users, including new users) can be provided reliably, and for developing and implementing policies related to curtailment to ensure the on-going reliability and security of the system.

5. An ISO should have control over the operation of interconnected transmission facilities within its region. An ISO is an operator of a designated set of transmission facilities.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading. A key function of an ISO will be to accommodate transactions made in a free and competitive market while remaining at arm's length from those transactions. The ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading over interfaces in some circumstances. It is important that the ISO's operational control be exercised in accordance with the trading rules established by the governing body. The trading rules should promote efficiency in the marketplace. In addition, we would expect that an ISO would provide, or cause to be provided, the ancillary services described in this Rule.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market. Management and administration of the ISO should be carried out in an efficient manner. In addition to personnel and administrative functions, an ISO could perform certain operational functions, such as: determination of appropriate system expansions, transmission maintenance, administering transmission contracts, operation of a settlements system, and operation of an energy auction. The ISO should use competitive procurement, to the extent possible, for all services provided by the ISO that are needed to operate the system. All procedures and protocols should be publicly available.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions. Appropriate price signals are essential to achieve efficient investment in generation and transmission and consumption of energy. The pricing policies pursued by the ISO should reflect a number of attributes, including affording non-discriminatory access to services, ensuring cost recovery for transmission owners and those providing ancillary services, ensuring reliability and stability of the system and providing efficient price signals of the costs of using the transmission grid. In particular, the Commission would consider transmission pricing proposals for addressing network congestion that are consistent with our Transmission Pricing Policy Statement. In addition, an ISO should conduct such studies and coordinate with market participants including RTGs, as may be necessary to identify transmission constraints on its system, loop flow impacts between its system and neighboring systems, and other factors that might affect system operation or expansion.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements. A free-flow

[425] A public utility is any person that owns *or operates* facilities used for the transmission of electric energy in interstate commerce or the sale of electric energy at wholesale in interstate commerce. An ISO will operate facilities used for the transmission of electric energy in interstate commerce and thus will be subject to the Open Access and OASIS rules.

of information between the ISO and market participants is required for an ISO to perform its functions and for market participants to efficiently participate in the market. At a minimum, information on system operation, conditions, available capacity and constraints, and all contracts or other service arrangements of the ISO should be made publicly available. This information should be made available on an OASIS operated by the ISO.

10. An ISO should develop mechanisms to coordinate with neighboring control areas. An ISO will be required to coordinate power scheduling with other entities operating transmission systems. Such coordination is necessary to ensure provision of transmission services that cross system boundaries and to ensure reliability and stability of the systems. The mechanisms by which ISOs and other transmission operators coordinate can be left to those parties to determine.

11. An ISO should establish an ADR process to resolve disputes in the first instance. An ISO should provide for a voluntary dispute resolution process that allows parties to resolve technical, financial, and other issues without resort to filing complaints at the Commission. We would encourage the ISO to establish rules and procedures to implement alternative dispute resolution processes.

G. Pro Forma Tariff

In the NOPR, the Commission stated that—

all utilities use their own systems in two basic ways: to provide themselves point-to-point transmission service that supports coordination sales, and to provide themselves network transmission service that supports the economic dispatch of their own generation units and purchased power resources (integrating their resources to meet their internal loads). [426]

Accordingly, the Commission proposed two pro forma tariffs in Appendices B and C of the NOPR: One for point-to-point service and one for network service. Our goal was to encourage the development of competitive bulk power markets by ensuring that all participants would be able to secure transmission services on a non-discriminatory basis. We attempted in the NOPR pro forma tariffs to articulate the minimally acceptable terms and conditions of service for point-to-point and network transmission service that were required to ensure non-discriminatory transmission service.[427] We explained that, for the most part, specific pricing provisions were omitted. We asked for comments on whether these tariffs provided a good basis for defining the minimum acceptable non-price terms and conditions of service.[428]

Subsequently, in a June 28, 1995 order, we encouraged public utilities to file open access transmission tariffs as soon as possible.[429] Tariffs with terms and conditions of service substantively similar to the NOPR pro forma tariffs would become effective without a refund condition, assuming there were no other concerns, *e.g.*, rate issues. We also indicated that these tariffs would be subject to revision based on the Final Rule.

Unified Pro Forma Tariff

The Commission received many comments on both the point-to-point and network tariffs. Many commenters suggested improvements to the proposed tariffs. Others took issue with how to reconcile various aspects of service under the two tariffs (*e.g.*, cost allocation, service priority, customer rights and obligations). As discussed below, the Commission has attempted to address these concerns in developing tariff requirements for the Final Rule. Importantly, while the Commission has retained point-to-point transmission service and network transmission service as distinct services, the requirements for the two services are now in a single pro forma tariff.[430] The Final Rule pro forma tariff eliminates many of the differences between the two NOPR pro forma tariffs, provides a unified set of definitions, and consolidates certain common requirements such as the obligation to provide ancillary services. The general terms and conditions of transmission service specified in the Final Rule pro forma tariff should be familiar to all utilities, particularly those that have voluntarily filed open access tariffs based on the NOPR pro forma tariffs.

The Commission believes that the modified, single pro forma tariff, in conjunction with the other requirements, is sufficient to remedy undue discrimination in the provision of transmission services. However, we note that in an accompanying notice of proposed rulemaking in Docket No. RM96–11–000, we are seeking comments on whether a different form of open access tariff—one based solely on a capacity reservation system—might better accommodate competitive changes occurring in the industry while ensuring that all wholesale transmission service is provided in a fair and non-discriminatory manner.

We address below the comments received on the NOPR tariff and the specific modifications we have made in the Final Rule pro forma tariff.

1. Tariff Provisions That Affect The Pricing Mechanism

a. Non-Price Terms and Conditions

Comments

Utilities For Improved Transition argues that any generic imposition of detailed tariffs on the electric industry will stifle the evolution of the industry. Rather, it asserts, utilities that supply transmission service should be permitted to apply general principles of comparability in their company-specific tariffs, using terms and conditions of service based on their own particular circumstances and those of their customers.

Utility Working Group wants the final rule to allow utilities to depart from the pricing method implicitly contained in the NOPR pro forma tariffs. It argues that the final rule should recognize that some terms and conditions may not make sense in the context of innovative pricing proposals.

DOE thinks that it is proper to base the tariffs on a familiar and simple pricing method. However, DOE suggests that, in the future, the Commission carefully assess the workability of the contract path model in a competitive bulk power market. DOE suggests that spot or real-time pricing should be considered.

Numerous commenters contend that the NOPR pro forma tariffs are based upon the contract path, embedded cost methodology. According to EEI and other IOU commenters, conforming changes may be needed to various terms and conditions of the tariffs to implement pricing methodologies that are not based upon contract path. These commenters argue that any flow-based model would necessitate different non-price terms and conditions. The commenters generally recognize the technical difficulties of implementing a flow-based model.[431] These commenters assert that the NOPR pro forma tariffs, as written, are not independent of pricing.

EGA criticizes the assumption underlying the contract path approach,

[426] FERC Stats. & Regs. ¶ 32,514 at 33,079.

[427] *Id.* at 33,092.

[428] On October 27, 1995, the Commission's staff sponsored a technical conference on the pro forma tariffs.

[429] American Electric Power Service Corporation, *et al.*, 71 FERC ¶ 61,393, modified, 72 FERC ¶ 61,287 (1995).

[430] The Final Rule pro forma tariff is attached as Appendix D.

[431] Additional comments concerning transition to flow-based pricing are summarized in Section IV.A.6.

i.e., that the capacities of individual transmission paths can be determined independently and made available to third parties. EGA notes that, in light of the competitive implications associated with transmission pricing, some utilities may propose other non-price terms and conditions suitable for other pricing methods, including power-flow-based tariffs. EGA expresses concern that the pro forma tariffs will be the only type of tariff allowed. EGA believes that the Commission should follow its transmission pricing policy guidelines and not impose a special burden on parties proposing tariffs that differ from the final rule pro forma tariffs, including non-price terms that support alternative pricing methods.

Some commenters also interpret the lack of reference to opportunity cost and incremental cost in the NOPR pro forma tariffs as a rejection of their use.[432]

Commission Conclusion

We agree that non-price terms and conditions cannot be designed independent of pricing and cost recovery. As discussed in detail below, the Final Rule pro forma tariff is intended to *initiate* open access, with non-price terms and conditions based on the contract path model of power flows and embedded cost ratemaking. It is designed based on the practices and procedures currently used by virtually all public utilities and complements the large number of tariffs already filed with the Commission. The Final Rule pro forma tariff is not intended to signal a preference for contract path/embedded cost pricing for the future. We recognize that the industry, in response to changes in institutions, competitive pressure, and technological innovations, is evolving rapidly. For example, various forms of flow-based pricing are beginning to be considered in conjunction with electronic transmission information systems. We seek to encourage this process and will in the future entertain non-discriminatory tariff innovations to accommodate new pricing proposals.[433]

In response to various comments, we are revising certain non-price terms and conditions where suggested changes either improve the tariff services or reconcile tariff inconsistencies. The nature of these tariff revisions does not appear to have serious cost consequences. The mandated changes are generally compatible with the rate proposals already filed by many public utilities. As discussed in Section IV.H., those utilities will not be required to file corresponding rate changes due to our mandated tariff changes to non-price terms and conditions, although they will be permitted to do so.

The Final Rule pro forma tariff includes specific terms and conditions rather than general principles. By initially requiring a standardized tariff,[434] we intend to foster broad access across multiple systems under standardized terms and conditions. However, in response to concerns raised by certain commenters, the tariff provides for certain deviations where it can be demonstrated that unique practices in a geographic region require modifications to the Final Rule pro forma tariff provisions. Accordingly, where applicable, the tariff permits the use of alternative non-price terms or conditions that are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider.

Finally, we will allow utilities to propose a single cost allocation method for network and point-to-point transmission services. These principles, as well as other modifications and clarifications to the NOPR pro forma tariffs, are discussed in detail below.

b. Load Ratio Sharing Allocation Mechanism for Network Service

Comments

Some commenters believe that load ratio cost allocation is appropriate for network service.[435] Other commenters argue that load ratio cost allocation is inappropriate, but disagree on the alternative. They offer a variety of other cost allocation and pricing methods.

The most frequent comment is that network and point-to-point services should be priced on the same basis. Florida Power Corp wants network contract demand to be offered and priced on a 12 CP basis.[436] ConEd and Duke argue that their systems are built and designed to meet a single peak; therefore, they contend that network service costs should be allocated with a load ratio calculation based on annual system peak rather than 12 CP. PSE&G claims that load ratio cost allocation works only if the customer has its own generation. Many commenters propose that ''behind the meter'' generation and load be eliminated from the network load ratio calculation.[437]

CINergy notes that the transmission provider's monthly load ratio calculation includes its long-term off-system firm service. It proposes that off-system sales be eliminated from the load ratio calculation to enable the transmission provider to offer discounts on long-term service. Alternatively, CINergy proposes that the revenues from these long-term off-system sales be shared with network customers based on their load ratio.

Atlantic City and Allegheny contend that cost allocation for network service should also reflect customers' relative energy use (*i.e.*, not just customers' coincident demand). Consequently, these commenters propose that cost allocation consider the network customer's actual load factor. Allegheny also proposes adding a minimum revenue provision to the load ratio method to recognize cost responsibility for non-peak use. Allegheny further proposes to include an increasing return on equity as available transmission capacity decreases. EEI proposes that cost allocation be based on a customer's non-coincident peak demand.

Lower Colorado River Authority proposes using load flow studies to determine planned use during the system peak with MW-mile billing units. It believes that this pricing method should be used for all transmission service to ensure comparable transmission pricing. Oklahoma G&E wants cost allocation to be based on the impacted MW-mile method, or alternatively, to determine embedded cost by voltage level. Centerior proposes the use of actual transfer capability instead of contract path capability in determining cost responsibility.

Orange & Rockland recommends some form of a ''poolco'' approach using locational marginal cost pricing. DOE also recommends using location-specific spot pricing (a form of marginal cost) for operating and congestion costs.

Public Generating Pool believes that load ratio share pricing is unworkable in the Pacific Northwest, in part because generation is generally located outside of the control area directly served by parties in the Northwest, and in part because BPA, which does not have a typical service territory, dominates the regional transmission market. Seattle states that cost allocation based solely on demand is inappropriate for systems

[432] *E.g.*, BPA, Utilities For Improved Transition, PG&E, Duke.

[433] We further clarify that, contrary to some commenters' interpretation, the Final Rule pro forma tariff is in no way a rejection of opportunity or incremental cost pricing.

[434] As noted in Section IV.H., public utilities may propose variations that are consistent with or superior to the terms and conditions in the Final Rule pro forma tariff.

[435] *E.g.*, PSNM, WP&L.

[436] Florida Power Corp's contract demand proposal would allow a network customer to nominate less than its full load for transmission service.

[437] *E.g.*, Cajun, NRECA.

that consist predominantly of hydro generation.[438]

AEC & SMEPA and NRECA are concerned about pancaked rates for network service that is provided to load served by more than one network tariff. Other commenters advocate use of some form of regional pricing.[439] American Wind proposes the use of a complex seasonal calculation, which appears to benefit wind energy. NY Com and Missouri-Kansas Industrials also express a preference for seasonal pricing models.

Commission Conclusion

We conclude that the load ratio allocation method of pricing network service continues to be reasonable for purposes of initiating open access transmission. Network service permits a transmission customer to integrate and economically dispatch its resources to serve its load in a manner comparable to the way that the transmission provider uses the transmission system to integrate its generating resources to serve its native load. Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to non-discrimination. We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning. Moreover, we recognize that alternative allocation proposals may have merit and welcome their submittal by utilities in future rate applications. They will be evaluated on a case-by-case basis and decided on their merits.

As to the concerns raised by AEC & SMEPA and NRECA about pancaked rates for network service provided to load served by more than one network service provider, we have stated that if a customer wishes to exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system, it may do so.[440] Customers that elect to do so, however, must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by ''behind the meter'' generation that seek to eliminate the load from their network load ratio calculation.

As noted, the most frequent comment is that the network and point-to-point services should be priced on a similar basis. This concern is addressed in the next section.

c. Annual System Peak Pricing for Flexible Point-to-Point Service

Comments

Commenters express concern that, if annual system peak capability is used to determine rates for point-to-point service and 12 CP is used to allocate costs for network service, point-to-point service may be underpriced relative to network service.[441] Therefore, many commenters propose pricing both services on the same basis.

EEI argues that flexible point-to-point service provides a premium service at a discount price. Therefore, EEI would increase the price unless the Commission either (1) eliminates the flexibility or (2) allows network customers to make non-firm sales at no additional charge. It recommends use of 12 CP for pricing both network and point-to-point service, but would credit point-to-point revenues to the cost of service for network and native load to avoid over-collection from contract demand point-to-point users. Alternatively, EEI contends that point-to-point service could use annual system peak capability pricing with a ratchet,[442] although EEI believes that 12 CP reflects the premium nature of long-term transmission. Under this alternative method, EEI notes that long-term non-flexible point-to-point service would use annual system peak pricing, while short-term service should be based on ''up to'' (ceiling) rates. In essence, EEI proposes a two-tier point-to-point service, with the first tier (flexible service) of equal priority in all respects to network service.[443] Ohio Edison also claims that, as proposed, flexible point-to-point service is a more valuable service than network service because it would be priced lower than network service. To correct for this difference, Ohio Edison would impose a separate rate for point-to-point non-firm use.

According to NRECA, unless the same measure of demand is included in the calculation of network and point-to-point charges, actual revenue from these two firm services will be greater than the actual cost of service. FL Com believes that flexible point-to-point service allows a transmission customer to engage in network economy transactions without incurring a full network charge, thus gaining an advantage over the transmission provider. Atlantic City recommends that the Commission either (1) eliminate the flexibility of point-to-point service or (2) price such service on a 12 CP basis. It claims that the use of an annual system peak capability creates a higher value service at a lower cost than network service. Based on its 1994 system data, Atlantic City claims that there is a 33 percent difference in rates between network and point-to-point services. Atlantic City also opposes the requirement to offer point-to-point service on an hourly basis, claiming that, unlike the point-to-point service customer, native load and network service customers are responsible for system investment year-round. Atlantic City also argues that point-to-point customers should pay for all non-firm use, *i.e.*, the Commission should eliminate the flexible nature of firm point-to-point service. PSE&G argues that point-to-point service should be used only for through-flow or out-flow transactions with all other transactions treated as network service. Thus, according to PSE&G, point-to-point service would not need flexibility.

If an annual system peak capability is used, Oklahoma G&E would redefine point-to-point service to eliminate the flexibility. FPL recommends either eliminating the flexibility to nominate secondary receipt and delivery points and receive non-firm service between them or pricing point-to-point service as premium service (*i.e.*, at a higher price than network service). Florida Power Corp claims that flexibility should be associated with network service, not point-to-point service. It also argues that revenues from point-to-point service should be credited against total transmission costs. It would similarly exclude point-to-point demands from the derivation of the network rate. Utility Working Group claims that if flexible point-to-point service is retained, such service should be priced at a higher (unspecified) rate or the non-firm secondary use should be separately priced. It believes that all users should

[438] Additional comments concerning the Pacific Northwest are summarized in Section IV.K.

[439] *E.g.*, OH Coops, Municipal Energy Agency Nebraska, UT Com.

[440] Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC ¶ 61,006 (1996), *reh'g pending.*

[441] Under the annual system peak method, system costs are allocated on the basis of each customer's contribution to the utility's annual system peak. Under the 12 CP method, system costs are allocated based on the average of the customer's usage at the time of the utility's 12 monthly system peaks.

[442] A ratchet is a billing provision that imposes minimum payment obligations on utility customers.

[443] *See also* Centerior, SCE&G, Detroit Edison.

pay for non-firm use, or if there is no additional charge under the point-to-point tariff, network customers and the transmission provider should be treated equally. SMUD argues that a user who does not want flexibility should have an option to elect a lower-priced non-flexible point-to-point service.

Commission Conclusion

We agree that pricing both services on a consistent basis may be appropriate. Consequently, we will allow a transmission provider to propose a formula rate that assigns costs consistently to firm point-to-point and network services. While not requiring the use of any particular rate methodology, we will no longer summarily reject a firm point-to-point transmission rate developed by using the average of the 12 monthly system peaks.

Our previous rationale for not using the average of the twelve-monthly peaks as a denominator in the development of non-customer specific transmission rates was enunciated in *Southern Company Services, Inc.,* 61 FERC ¶ 61,339 (1992) (*Southern*). In *Southern,* the Commission was concerned that establishing a system-wide, non-customer specific transmission service rate that did not appropriately account for diversity [444] among various transmission customers might result in the over-recovery of revenues for point-to-point service. Inherent in our ruling in *Southern* was the understanding that once a sufficient pattern of customer usage under the tariff was established, the company was free to file a customer-specific rate using the average of the 12 monthly system peaks for cost allocation. We still believe that it is appropriate for utilities to use a customer-specific allocated cost of service [445] to account for diversity, but based on the changed circumstances since *Southern* (which we discuss below) we will now permit an alternative.

We also note that the circumstances in *Southern* are distinguishable from those now present in the industry. Southern proposed a rigid, inflexible firm point-to-point transmission service where the customer paid separately for each delivery and receipt point combination. The only flexibility permitted was to use alternative receipt and delivery points on a non-firm basis at no additional charge. As the name implies, the flexible nature of the point-to-point transmission service proposed in the NOPR is more akin to the service provided to native load and network service customers. Contrary to what was proposed in *Southern,* point-to-point service does not require separate charges for each firm service receipt and delivery point combination. Rather, customers pay on the basis of the higher of the total delivery points or total receipt point combination. Flexible point-to-point transmission customers continue to be able to access alternative receipt and delivery points on a non-firm basis without additional charges (as long as they remain within their capacity reservation). In addition, firm point-to-point customers can reassign and resell unused portions of their reserved firm capacity to third parties. With flexible firm and non-firm point-to-point transmission service, the transmission provider must make firm point-to-point transmission capacity available to the customer regardless of its load characteristics or use.

For these reasons, we will allow all firm transmission rates, including those for flexible point-to-point service, to be based on adjusted system monthly peak loads. The adjusted system monthly peak loads consist of the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with *all* firm point-to-point service customers plus the monthly contract demand reservations for *all* firm point-to-point service.

The flexibility and reassignment rights of this transmission service require the transmission provider to hold the firm contract capacity available regardless of the customer's own load characteristics or its actual use. In other words, a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. For these reasons, it is appropriate to consider a firm reservation as the equivalent of a load for cost allocation and planning purposes.

In order to prevent over-recovery of costs for those who use this approach, we will require transmission providers to include firm point-to-point capacity reservations in the derivation of their load ratio calculations for billings under network service. In addition, revenue from non-firm services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates. The combination of allocating costs to firm point-to-point service and the use of a revenue credit for non-firm service will satisfy the requirements of a conforming rate proposal enunciated in our Transmission Pricing Policy Statement.[446]

d. Opportunity Cost Pricing

(1) Recovery of Opportunity Costs

Comments

EEI and IOUs generally support the notion that transmission customers should pay some form of opportunity cost when transmission is constrained and request that the final rule clearly define redispatch and opportunity costs. These commenters generally agree that the final rule should codify these terms consistent with recent Commission orders addressing opportunity costs.

Duke requests that the final rule clarify that the transmission customer should pay all the opportunity costs associated with modified dispatch. Centerior argues that redispatch costs include consideration of parallel flows and scheduled deliveries, which, according to Centerior, cause redispatch costs to be incurred.

Florida Power Corp and NYSEG state that redispatch costs should be either rolled in or charged on an incremental basis, consistent with the Commission's ''or'' pricing policy. Florida Power Corp recommends that an opportunity cost recovery provision be added to the ''Rates and Charges'' sections of the tariffs. NYSEG recommends that the tariffs implement the Commission's recent ruling in *Florida Power & Light Company,* 66 FERC ¶ 61,227 (1994), allowing lost opportunity costs to be recalculated annually. NYSEG believes that: (1) Redispatch costs should be collected for any period in which the transmission customer causes a constraint, including the period of time it takes to construct incremental facilities necessary to alleviate the constraint; (2) network customers should be responsible for any opportunity costs incurred as a result of their non-firm use of the system if such costs rise to a level above their load ratio share of system costs; and (3) point-to-point customers should be responsible for any opportunity costs incurred as a result of their non-firm use of the transmission provider's system up to their reserved firm entitlement.

Ohio Edison believes that, given the unique nature of network service, it is inappropriate to require network service customers to incur redispatch costs in order to create additional capacity. PECO requests that the final rule clearly indicate (1) from whose perspective

[444] In this context, diversity occurs when a customer's peak demand is not coincident with the transmission provider's system peak demand.

[445] The use of this rate design is particularly applicable where customers who were taking bundled service convert to transmission-only service under the point-to-point tariff and ensures that transmission costs are allocated to point-to-point customers and network customers in a consistent manner.

[446] FERC Stats. & Regs. ¶ 31,005 (1994).

''least cost'' redispatch is judged and (2) that the ''least cost'' redispatch obligation is subordinate to reliability.

Concerned that transmission providers could manipulate the calculation of redispatch charges to increase profits, NRECA proposes that transmission providers develop formal redispatch protocols that would be provided to all customers. NRECA argues that all information necessary to calculate redispatch costs should be made available on the RIN. Customers assessed redispatch charges should be provided with all the necessary information to evaluate such charges, including full audit rights. NRECA, Cajun, and PacifiCorp object to the inclusion of ''lost opportunity'' costs in redispatch charges. NRECA proposes that only actual non-firm sales or purchases should be included in the calculation of opportunity costs.

United Illuminating and Seattle state that all opportunity costs should be assessed to short-term and non-firm transmission service customers that cause the transmission provider to redispatch its generation to unload a constrained transmission line. According to United Illuminating, it is not appropriate to roll opportunity costs into the rates charged other transmission users because existing users do not have the choice to pay the opportunity costs or to allow their transaction to be curtailed.

UtiliCorp, on the other hand, states that all ''out of rate'' uneconomic dispatch costs should be rolled in and recovered from all users of the transmission system. UtiliCorp argues that directly assessing these costs to a particular customer would unfairly penalize a customer who could not gain access to a system until after the tariffs take effect.

CCEM argues that only lost opportunity costs associated with the loss of *firm* purchases or sales should be recoverable. CCEM also believes that the transmission provider should calculate the redispatch costs in advance and transmission customers should be able to opt out of redispatch if costs rise above a certain level.

Commission Conclusion

We will retain redispatch provisions in the Final Rule pro forma tariff, but clarify that redispatch is required only if it can be achieved while maintaining reliable operation of the transmission system in accordance with prudent utility practice.

We find that the recovery of redispatch cost requires that: (1) A formal redispatch protocol must be developed and made available to all customers; and (2) all information necessary to calculate redispatch costs should be made available to the customer for audit.

As discussed in the Section IV.H., the Commission is according substantial flexibility to public utilities to propose appropriate pricing terms, including opportunity cost pricing, in their compliance tariff. However, as with any compliance filing, the rates proposed must meet the standards for conforming proposals in the Transmission Pricing Policy Statement.

In *Northeast Utilities* and *Penelec,* we fully explained our rationale for allowing utilities to charge opportunity costs.[447] We concluded that a public utility is entitled to full compensation for all ''legitimate'' and ''verifiable'' costs it incurs to provide firm transmission service.[448] We explained that where a utility can demonstrate that additional opportunity costs are incurred as a direct result of providing transmission service, our pricing principles would permit recovery of those costs. The Commission further explained in the Transmission Pricing Policy Statement that when transmission capacity is constrained and a utility does not expand capacity, we have allowed the utility to charge transmission customers the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two (*i.e.,* ''or'' pricing is permitted; ''and'' pricing is not). The opportunity costs are capped by incremental expansion costs.[449]

Transmission providers proposing to recover opportunity costs must adhere to the following requirements:

(1) A fully developed formula describing the derivation of opportunity costs must be attached as an appendix to their proposed tariff.

(2) Proposals must address how they will be consistent with comparability.

(3) All information necessary to calculate and verify opportunity costs must be made available to the transmission customer.

(2) Fuel Adjustment Clause Treatment for Redispatch Costs

If the transmission provider proposes to separately collect redispatch costs on a direct assignment basis from a specific transmission customer, we will require that the transmission provider credit these revenues to the cost of fuel and purchased power expense included in its wholesale fuel adjustment clause.

e. Expansion Costs

Comments

ELCON argues that direct assignment of 100% of the costs of expanding a constrained transmission system to a particular customer is unfair. NY Energy Buyers believes that the costs of expanding the transmission system should be shared among all customers seeking transmission service. Alternatively, NY Energy Buyers states that if direct assignment of system expansions is adopted, such costs should be payable both by new wholesale customers and by new retail load. According to NY Energy Buyers, it would be preferable for the utility to treat all requesters during a given period as making one request for a large increment of capacity, with all requesters paying the same average incremental cost. New native load also should be considered to be a requester of transmission capacity and allocated an appropriate share of any expansion costs.

CA Energy Co believes that incremental pricing will discriminate against all later competitors by charging higher rates. It advocates rolled-in pricing with the requirement that all users requesting system expansion commit to service for a term that will cover their proportionate expansion cost assignments.

FPL proposes that costs associated with normal load growth and the repair and/or replacement of older facilities be rolled in with the other embedded transmission costs and shared on a load ratio basis. However, it believes that transmission expansions associated with the addition of a new resource should be separately assigned.

On the other hand, Orange & Rockland maintains that unless expansion costs are directly assigned, an unfair subsidization will occur. According to PECO, transmission customers should be assigned costs for system upgrades under both the network and point-to-point tariffs. Consumers Power claims that the network tariff is unclear about which facilities are directly assignable, and proposes that all costs that exceed the

[447] Northeast Utilities Service Company (*Northeast Utilities*), 56 FERC ¶ 61,269 (1991), *order on reh'g,* 58 FERC ¶ 61,070, *reh'g denied,* 59 FERC ¶ 61,042 (1992), *order granting motion to vacate and dismissing request for rehearing,* 59 FERC ¶ 61,089 (1992), *aff'd in relevant part and remanded in part,* Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993); Pennsylvania Electric Company (*Penelec*), 58 FERC ¶ 61,278 at 62,871–75, *reh'g denied,* 60 FERC ¶ 61,034 (1992), *affd,* Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993).

[448] *Penelec,* 58 FERC at 61,872; 60 FERC ¶ 61,034 at 61,126 (1992).

[449] FERC Stats. & Regs. ¶ 31,005 at 31,138.

embedded average cost qualify for direct assignment.

SMUD requests that the final rule clarify that if a transmission customer invests in incremental facilities, it will be entitled to ownership-like rights to the capacity addition.

In order to avoid possible argument over the necessity and cost of system expansions for a particular transmission request, NIEP requests that the final rule require utilities to use a ''least-cost'' approach to transmission expansion that includes comparable transmission expansion practices for all wholesale customers.

According to Duke, the concern that the transmission provider's retail customers will retain an advantage by having expansion costs placed on third parties is misplaced. Duke argues that, under ''or'' pricing, the issue of who is responsible for expansion costs would still arise. It contends that the Commission will have to decide on a case-by-case basis whether expansion costs are incurred for the benefit of a specific party or are part of overall network costs. Duke generally supports the current ''or'' pricing policy.

Citing the Commission's Transmission Pricing Policy Statement, FL Com supports the flexibility of charging both embedded cost and incremental cost transmission rates, *i.e.*, ''and'' pricing. It argues that, because of the dynamic and interconnected nature of the transmission system, tariff customers causing expansion costs should be held responsible for both the incremental cost of the addition and some portion of the existing transmission system needed to support the addition. FL Com states that the comparability standard is at odds with the Commission's non-conforming transmission pricing policy, particularly with respect to ''and'' pricing.

Commission Conclusion

Under the Final Rule pro forma tariff, we will allow transmission providers to propose any method of collecting expansion costs that is consistent with our transmission pricing policy. We disagree with ELCON's assertion that directly assigning the costs for expanding a constrained transmission system is necessarily unfair. As we stated in *Northeast Utilities*, if the cost of expansion is directly attributable to a customer's request for transmission service and the expansion would not be undertaken ''but for'' that customer's request, then it is reasonable to assign the cost of expansion to that customer. If we were not to allow the direct assignment of expansion costs to the customer causing the expansion, then other customers would subsidize the new customer's use of the transmission system. We continue to believe that ''or'' pricing sends the proper price signal to customers and promotes efficiency. Under the tariff, any assignment of future expansion costs must meet the standards for conforming proposals in the Transmission Pricing Policy Statement. Recovering expansion cost based upon ''and'' pricing will not be allowed.

Any request to recover future expansion costs will require a separate section 205 filing. The Commission will evaluate, on a case-by-case basis, who is responsible for expansion costs in those filings and whether direct assignment of those costs is appropriate.

f. Credit for Customers' Transmission Facilities

Comments

Most commenters agree that the Commission must clearly define when a network customer's transmission facilities warrant a credit from the transmission provider. Several commenters state that customers must bear the burden of demonstrating that their facilities are used by and useful to the transmission provider, provide direct benefits, and support the operation of the transmission system.[450] EEI cautions against providing a credit for facilities that may be integrated with, but of no effective benefit to, the operation of the bulk power system.

The costs associated with customer-owned facilities that are used by the transmission provider should, in PECO's opinion, be recovered from the transmission provider under the customer's own transmission tariff.

FPL cautions that the position of certain parties that transmission facilities warrant a credit if they would have been included in the transmission provider's rates could produce absurd results. It claims that it could actually end up paying a network customer with substantial transmission investment for the right to provide that customer service. FPL contends that it will receive absolutely no service from its network customers because FPL would not need, nor could it use, any of the customers' transmission facilities to integrate FPL's loads and resources. FPL argues that crediting under the so called ''rate base'' test obligates the transmission provider to purchase a load-ratio share of the customer's transmission facilities. FPL states that, under network service, the transmission provider and the network customer will not create a single system.

AEP recommends that a network customer receive a credit if its transmission facilities meet the following criteria: (1) At points of interconnection, there must be a through-flow of power from the network customer's system to the transmission provider's system under normal operating conditions; and (2) the customer's facilities must: (a) Increase the transfer capability of an interface on the transmission provider's system; (b) provide an alternative path for power flows during transmission facility outages, thus increasing the reliability or stability of the combined system; or (c) otherwise satisfy the transmission provider's planning criteria for the installation of network facilities.

WP&L argues for a broader standard and states that a transmission customer should be entitled to a credit if the transmission owner would have installed similar facilities to provide service for its own native load under similar circumstances. Florida Power Corp states that the credit for each facility should be determined on a case-by-case basis.

PacifiCorp argues that a utility may take advantage of the transmission credit and shift major transmission investment onto another transmitting utility and its transmission customers by simply becoming a network customer. PacifiCorp claims that such a situation may, for example, exist for BPA as a transmitting utility. According to PacifiCorp, preliminary studies indicate at least one potential network customer may be entitled to a transmission credit which would exceed that customer's charges for BPA's network integration service.

APPA, Blue Ridge, and Cajun maintain that a customer's facilities should be evaluated on a basis comparable to the facilities included in the rates of transmission providers in a region. APPA argues that a claim that the transmission customer's facilities do not benefit the transmission system must be weighed against the fact that some facilities included in the transmission provider's rate base may not directly benefit the transmission customer. Cajun advocates setting clear standards for the identification of customer-owned transmission facilities eligible for crediting and clear guidelines for determining the amount of the credit.

SMUD not only supports the credit under the network tariff, but also would extend the credit to facilities used to complete a transaction under the transmission provider's point-to-point tariff.

[450] *E.g.*, EEI, Consumers Power.

Commission Conclusion

Because of the diverse concerns raised by the commenters, we are unable to resolve on the basis of this record the extent to which, or under what circumstances, cost credits related to customer-owned facilities would be appropriate under an open-access transmission tariff. We conclude that such credits are more appropriately addressed on a case-by-case basis, where individual claims for credits may be evaluated against a specific set of facts.

We stress that while certain facilities *may* warrant some form of cost credit, the mere fact that transmission customers may own transmission facilities is not a guaranteed entitlement to such a credit. The presumption of many commenters that a customer's subscription to transmission service somehow transforms the provider's and customer's systems into an expanded integrated whole to the mutual benefit of both is not a valid one. As we ruled in *Florida Municipal Power Agency* v. *Florida Power & Light Company* (*FMPA*), it must be *demonstrated* that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider. Specifically, we stated that:

> The integration of facilities into the plans or operations of a transmitting utility is the proper test for cost recognition in such cases. The mere fact that a section 211 requestor has previously constructed facilities is not sufficient to establish a right to credits.[451]

The fact that a transmission customer's facilities may be *interconnected* with a transmission provider's system does not prove that the two systems comprise an *integrated* whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over those facilities—a key requirement of integration.[452] We also note that consistent with our ruling in *FMPA*, if a customer wishes not to integrate certain loads and resources, and thereby exclude them from their load ratio share of the allocated cost of the integrated system, it may do so. Customers that elect to do so, however, should recognize that they may need to secure alternative transmission arrangements such as point-to-point transmission service on an as-available basis in order to utilize those resources for reserves.

Where disputes over credits for customer-owned transmission facilities arise, we encourage all parties to first pursue alternative means to resolve their differences rather than seek formal resolution at the Commission. In any event, the Commission anticipates that disputes over the appropriate level of transmission facility credits should not preclude transmission customers from initiating service under the tariff. Where the parties are unable to reach agreement on the appropriate credit for customer-owned transmission facilities, the parties may make an appropriate filing with the Commission.

g. Ceiling Rate for Non-Firm Point-to-Point Service

Comments

Commenters generally support a ceiling rate for non-firm transmission service, capped at the firm rate.[453] Others request clarification as to whether the point-to-point tariff rates are fixed or are ceiling rates. Central Illinois Public Service's major concern is that, if the rates are fixed, the tariffs may result in higher prices for capacity and energy than those currently allowed for bundled service.

NYSEG argues that unequal pricing is a natural phenomenon of the open marketplace and requests assurance that offering transmission service at prices below a cost-based ceiling rate will not expose a transmission provider to claims of undue discrimination.

AEC & SMEPA opposes using the firm rate as the cap for non-firm transmission service. It states that, given the substantially lower quality of non-firm service (with no obligation to plan for such service), no cost-of-service principle justifies charging rates for non-firm service as high as the rate for firm service.

EGA and NRECA state that any discounts from the maximum firm rate must be uniform, transparent, readily understood, and posted on a RIN. According to CCEM and NRECA, the transmitting utility must have nondiscriminatory discount practices and must contemporaneously offer discounts to transmission customers at the same time and on the same basis as discounts for internal sales operations or affiliates.

Commission Conclusion

We believe that it is important to continue to allow pricing flexibility. In accordance with the Commission's current policies, the rate for non-firm point-to-point transmission service may reflect opportunity costs. Any provisions for opportunity cost pricing for non-firm service must meet the requirements already discussed. If a utility chooses to adopt opportunity cost pricing, the non-firm rate is effectively capped by the availability of firm service and is not subject to a separately-stated price cap. If a utility chooses not to adopt opportunity cost pricing, the non-firm rate is capped at the firm rate. We also wish to ensure that non-firm transmission service is priced in a nondiscriminatory fashion. Accordingly, if a transmission provider offers a rate discount to its affiliate, or if the transmission provider attributes a discounted rate to its own transactions, the same discounted rate must also be offered at the same time to non-affiliates on the same transmission path and on all unconstrained transmission paths. We will further require that any affiliate discounts from the maximum firm rate must be transparent, readily understandable, and posted on the transmission provider's OASIS in advance so that all eligible customers have an equal opportunity to purchase non-firm transmission at the discounted rate.[454] In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory and must be reported on the OASIS within 24 hours of when available transmission capability (ATC) is adjusted in response to the transaction. As discussed in the RIN section, information, including the price for all non-firm transaction discounts, must be posted on the OASIS to ensure comparability.

2. Priority for Obtaining Service

Comments

The term ''priority'' is used in the comments in several senses. The intent of the comment depends on which kind of ''priority'' is intended. In general, there are comments about the order in which parties can obtain new service, which we call ''reservation priority,'' and there are comments about the order in which parties lose service they already have, which we call ''curtailment priority.'' Commenters may establish different reservation priorities for various services, such as network, off-system sales, firm, ability to reserve a portion of new transmission

[451] 74 FERC ¶ 61,006 at 61,010 (1996), *reh'g pending.*

[452] We caution all transmission providers that while our discussion here addresses the requirements necessary for a customer's transmission facilities to become eligible for a credit, the principles of comparability compel us to apply the same standard to the transmission provider's facilities for rate determination purposes.

[453] *E.g.*, Duke, SCE&G, AEP, FPL.

[454] The same requirements will apply to discounts from firm transmission service. Similarly, if a transmission provider offers an affiliate a discount for ancillary services, or attributes a discounted ancillary service rate to its own transactions, it must offer at the same time the same discounted rate to all eligible customers. Discounted ancillary services rates must be posted on the OASIS pursuant to new Part 37 of the Commission's regulations.

capacity to be constructed, and so on. Curtailment priorities also differ with the type of service. However, many commenters assert that certain parties should or should not have ''priority'' without distinguishing the kind of priority or type of service for which priority is intended.

a. Reservation Priority for Existing Firm Service Customers

Comments

Many IOUs, state commissions, and cooperatives strongly believe that native load should have priority to reserve transmission capacity under the tariffs.

EEI suggests that existing and future allocations of transmission capacity must be based on proper transmission pricing or, in its absence, priority of service. According to EEI, retail and existing wholesale requirements service should have the highest priority for use of transmission capacity, followed by long-term point-to-point service. Dayton P&L supports a continued preference for native load growth because native load customers have borne the majority of the costs of the transmission system. Detroit Edison, EEI, and Florida Power Corp claim that, because native load and network customers pay higher rates during all hours, such customers should have higher priority for service requests than others requesting transmission service. These commenters also claim that the transmission provider should be able to reserve firm capacity for native load and network service customers.

Similarly, NARUC wants wholesale and retail native load customers to be held harmless from functional unbundling of wholesale transmission services. Because these customers have borne the vast majority of the costs of the utility's transmission facilities, NARUC argues that priority of service, quality of service, and allocation of joint and common costs to native load customers should not be affected by the transition to an open access transmission regime.

PA Com does not share the Commission's concern that a transmission provider may discriminate against a third party transmission customer vis-a-vis native load. It finds nothing impermissible in this sort of discrimination, arguing that the interconnected system was financed by, designed for, and built to serve native load.

NRECA explains that most transmission customers that seek network service will already be receiving similar service (albeit in a bundled form) from their transmission providers. It argues that these customers should receive the same priority of service as the transmission provider's native load customers for as long as they continue to take network service, whether under a current bundled wholesale supply contract, a private transmission contract, or a network tariff.[455]

East Kentucky requests that the final rule clarify that member distribution cooperatives of G&Ts will have priority over third parties in the use of the G&T's existing transmission facilities. TVA comments that native load customers and emergency service to neighboring systems should have a higher service priority than transmission services sold to third parties (where an alternative power supply is available to the third party).

Commission Conclusion

We reiterate that we are not requiring the transmission provider to unbundle transmission service to its retail native load nor are we requiring that bundled retail service be taken under the terms of the Final Rule pro forma tariff. However, the amount of transmission capacity available to wholesale and unbundled retail customers under the Final Rule pro forma tariff is clearly affected by the amount of transmission capacity that the transmission provider reserves for the use of its native load customers and the future load growth of those customers. The transmission provider may reserve in its calculation of ATC transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon. However, the transmission provider is obligated to provide transmission service to others under the Final Rule pro forma tariff out of capacity reserved for native load growth up to the time the capacity is actually needed for such future needs. Furthermore, as we explained previously, while existing wholesale customers do not have any ownership-like rights to the capacity they used during the term of their contract, they will have a right of first refusal to that capacity after the expiration of their contracts or when their contracts become subject to renewal or rollover.[456]

b. Reservation Priority for Firm Point-to-Point and Network Service

Comments

A number of commenters argue that all firm service should *not* be treated equally. These commenters argue that the price of the service should determine the priority that the service receives. A large number of IOUs and potential network customers (existing requirements customers) argue that in light of the pricing implicit in the NOPR, (*i.e.*, 12 CP for network versus annual system peak for point-to-point) network service should have priority over point-to-point service (because, all other things being equal, the price for network service will be higher).

BG&E believes that a customer receiving service priority equal to native load and network customers should pay comparable rates. Thus, BG&E argues that either flexible firm point-to point service should be priced the same as network service, or point-to-point service should have a lesser priority than native load and network service customers if point-to-point service is priced lower than network service.

DE Muni believes that native load and network customers must have priority access to interfaces (particularly where they are constrained) after system reliability concerns have been satisfied. The same argument is advanced by commenters concerning long-term service versus short-term service. Public Generating Pool argues that long-term service should always have priority over short-term service because long-term customers contribute more towards fixed-cost recovery than do short-term customers.

Cajun objects to having its service and service to its customers, which it characterizes as network service, receive the same priority as firm point-to-point service customers who take service for periods as short as one hour. Cajun points out that it, as well as other network and native load customers, have been paying and will be paying for the transmission facilities in place to serve their needs for many years. According to Cajun, the transient firm point-to-point customer should not have equal standing. Cajun suggests, however, that a long-term firm point-to-point customer taking service for ten years or more should have service priority equal to native load and network service customers.

SC Public Service Authority argues that the availability of short-term firm service with a priority equal to long-term service would provide a means for short-term customers to obtain the advantages of long-term firm service at a much lower total cost. As a result, it argues that a few point-to-point customers would opt for long-term firm service, and the burden of the residual costs of the transmission system would fall on network customers.

EEI claims that priority for point-to-point service should be on a continuum of firmness, with reservation (as well as

[455] *See also* American Forest & Paper, AMP-Ohio.

[456] *See* discussion in Section IV.A.5.

curtailment) priority based upon duration of service and specific negotiated terms. EEI proposes that the point-to-point tariff be modified to provide a first-tier category of flexible point-to-point transmission service that is comparable in priority, price, length, and terms of service to network service. EEI believes that this modification will resolve the problems that are associated with establishing priorities between network service and point-to-point service if the Commission retains different CP cost allocation methods for each service.

On the other hand, CCEM, a group of power marketers, supports the concept that all firm service should be treated equally, regardless of the term or the nature of service.

Commission Conclusion

An essential element of non-discriminatory transmission access is the right of transmission customers to reserve and purchase transmission service that is of the same quality as that used by the transmission provider in serving its wholesale requirements customers and retail load. Thus, we reject the proposal of some commenters that transmission providers need not provide firm point-to-point service that is of the same ''firmness'' as the transmission provider's service to native load. However, the fact that both network service and point-to-point service are provided on an equally firm basis does not mean that both types of service must be priced or reserved in the same manner.

The comments about reservation priorities for firm services boil down to two concerns. First, due to the differences in pricing firm point-to-point service and network service implicit in the NOPR (*i.e.*, twelve-monthly CP pricing for network versus annual system peak for point-to-point), some commenters believe that network service should have priority over point-to-point service. Second, some commenters maintain that according firm, short-term point-to-point service a priority equal to long-term service provides a means for short-term customers to avoid making a fair contribution to the long-term costs of the system.

With respect to the first concern, we have eliminated the differences in pricing by permitting utilities to adopt point-to-point reservations as the customer load. As discussed above, for purposes of the Final Rule pro forma tariff, utilities are free to propose a single cost allocation method for the two services.

The second area of concern arises because of the first-come first-served reservation priority in the NOPR point-to-point tariff. The Commission recognizes that the tariffs, as proposed in the NOPR, provide the opportunity for a customer to reserve certain valuable rights (*e.g.*, the right to short-term firm service during peak periods) while avoiding in part the long-term costs of the system (perhaps by relying on non-firm service during lengthy off-peak periods when there is a substantially reduced chance of interruption). However, the Commission has a countervailing concern that the transmission provider should not be able to withhold valuable transmission capacity from potential customers if that capacity is not being used by those who are paying for the long-term costs of the system.

Accordingly, the Final Rule pro forma tariff provides a mechanism to address this concern while safeguarding the rights of potential customers to obtain access to unused capacity. The tariff provides that reservations for short-term firm point-to-point service (less than one year) will be conditional until one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. These conditional reservations may be displaced by competing requests for longer-term firm point-to-point service. For example, a reservation for daily firm point-to-point service could be displaced by a request for weekly firm point-to-point service during an overlapping period. Before the applicable reservation deadline, a holder of a conditional firm point-to-point reservation would have the right of first refusal to match any longer-term firm point-to-point reservation before being displaced. After the deadline, the reservation becomes unconditional, and the service would be entitled to the same priorities as any long-term point-to-point or network firm service.[457]

The Final Rule pro forma tariff does not propose point-to-point or network service with various degrees of firmness beyond the simple categories of firm and non-firm. When a customer requests firm transmission service, reservation priorities are established based first on availability, and in the event the system is constrained, based on duration of the underlying firm service request; customers may choose the ''firmness'' of service they want by electing to take non-firm service, or by reserving and paying for firm service. We have not included any degrees of firmness in the Final Rule pro forma tariff because having intermediate categories of firmness under point-to-point or network service would, we believe, unnecessarily complicate the priority system. However, utilities are free to propose and fully support different reservation priority provisions for firm service in subsequent rate filings as long as those provisions are not unduly discriminatory, fully comply with the principles of comparability, and are priced appropriately.

c. Reservation Priorities for Non-Firm Service

Comments

IOUs, state commissions, and potential network customers tend to support the service reservation priorities for non-firm service set forth in the NOPR pro forma tariffs (*i.e.*, transmission service by network customers for economy purchases to serve network load has a higher priority than non-firm point-to-point service, which has a higher priority than a firm point-to-point customer using transmission service at secondary points of receipt and delivery). However, because network customers pay a higher rate than point-to-point customers, these commenters argue that network customers should be permitted to use their off-peak load ratio share of the transmission system to make off-system sales. Many commenters argue that point-to-point customers can use their secondary service for both purchases and sales; thus, they believe it is discriminatory to limit network customers to purchases at secondary points.

Commenters that are opposed to the service reservation priority scheme in the NOPR pro forma tariffs argue that transmission providers will discriminate against third party users in favor of their native load economy purchases. These commenters argue that all non-firm service should have equal priority.

Other commenters, such as CINergy, would base priority on the duration of service. CINergy claims that this method would eliminate what it claims is an advantage (over network) given in the NOPR to point-to-point service in making short-term purchases. TVA notes that it establishes priority for non-firm service based on duration of service requested, with customers in each service category receiving priorities based on the rate they wish to pay.

Some commenters believe that the transmission price should affect the

[457] The service itself, as opposed to reservations, is subject to the curtailment provisions discussed below.

priority of customers to obtain non-firm transmission capacity.[458] However, other commenters argue that this seems to be precluded by the NOPR pro forma tariffs' service priority provisions.

Although PSE&G believes that the NOPR pro forma tariffs suggest a first-come, first-served allocation method for capacity in excess of that needed for firm transmission service, it proposes a fixed period of time for all potential users to submit bids for service (*e.g.*, one week prior for monthly service), allowing the bid price to determine priority (*i.e.*, the higher bid prices receive service priority over lower bid prices). According to PSE&G, customers could bid an ''up to'' rate subject to a price floor, with all revenues flowed back to firm service customers. TVA also advocates departing from the first-come, first-served approach for allocating some uses of the transmission system, claiming that price is an effective means to establish priority for non-firm and short-term firm services.

Utility Wind Interest Group requests that non-firm service used for transmitting renewable resources be given a higher priority than non-firm service used for transmitting conventional resources because renewable resources cannot store their fuel supply.

Commission Conclusion

We continue to believe that network economy purchases should have a reservation priority over non-firm point-to-point and secondary point-to-point uses of the transmission system. Network transmission customers are obliged to pay all of the costs of the transmission system without regard to the resources from which energy is scheduled. Therefore, it is appropriate that the transmission associated with a network customer's economy purchases (*i.e.*, transmission that is used to substitute one resource for another on an as-available basis) enjoys a higher priority than non-firm point-to-point transmission service.

Regarding the reservation priority for non-firm service under point-to-point service, we will adopt a reservation priority based upon duration of non-firm service, with price acting as a tie-breaker for competing service requests of an equal duration. If there is insufficient transmission capacity to accommodate all non-firm transmission requests, the reservation of longer duration should displace the shorter. For example, a reservation for a month of non-firm service will displace a reservation for a week of non-firm service. Also, a reservation for a week will displace a reservation for a day, which will displace a reservation for an hour of non-firm service. If a customer requests non-firm and later another customer requests longer-term non-firm service before either term of service begins, the first customer to request service has the right of first refusal to change its request to the longer term of service. A firm point-to-point customer's use of transmission service at secondary points of receipt and delivery will continue to have the lowest reservation priority.

3. Curtailment Provisions

a. Pro-Rata Curtailment Provisions

Comments

A large number of IOUs that are control area operators argue for discretion to curtail the transaction that most effectively relieves the constraint, in lieu of mandatory pro-rata curtailments, which they argue are inappropriate and not cost effective.

Other commenters that do not support pro-rata curtailment argue that preference should be given to native load or existing customers because these customers have paid the majority of the costs of the transmission system. A large number of customers note that their existing contracts contain ''enhanced'' curtailment priorities (*i.e.*, service to others will be curtailed before service to customers with such curtailment priority) due to the large capital outlays made by them in connection with their service.[459]

Public Generating Pool believes that the proposed curtailment provisions may not be flexible enough for transactions in the Northwest. It argues that hydro spill should be avoided, and suggests that transactions from federal and/or non-federal hydroelectric generation facilities should not be curtailed pro rata with other transactions that do not rely on such facilities. Public Generating Pool urges that regional agreements (*e.g.*, regional transmission group agreements) that would achieve this goal should be given deference.

Other commenters support pro-rata curtailments for firm service.[460] PSNM states that this has been its operating practice in the past, and PSNM expects to continue such an approach in the future.

Power marketer commenters generally support the pro-rata curtailment adding that a standardized curtailment priority applied nationally would provide greater open access and eliminate discriminatory curtailments.

Commenting on a related subject, EEI maintains that the network tariff provision for termination of service in the event a customer fails to curtail load[461] may not be realistic for service to a Transmission Dependent Utility. EEI suggests that the Commission supplement this provision with a substantial penalty provision, coupled with an indemnification requirement.

Commission Conclusion

It was not our intent in the NOPR to require all transactions to be curtailed on a pro-rata basis regardless of whether the transaction relieves a constraint. We intended to permit curtailments of transactions that substantially relieve a constraint.[462] We intended and continue to believe that curtailment on a pro-rata basis is appropriate for curtailing the transactions that substantially relieve the constraint. In order to allay the concerns of the commenters addressing this issue, we are clarifying the curtailment provision of the tariff to explicitly allow the transmission provider discretion to curtail the services, whether firm or non-firm, that substantially relieve the constraint. Of course, any curtailment must be made on a non-discriminatory basis, including curtailment of the transmission provider's own use of the transmission system. Customers that believe the curtailment policy is administered unfairly may file a section 206 complaint at the Commission.

Concerning the request of certain Pacific Northwest commenters, we would consider granting deference to an alternative curtailment method to avoid hydro spill if such a regional practice is generally accepted and adhered to across the region, as discussed further in Section IV.K.

Finally, we agree with EEI's observation that terminating network

[458] *E.g.*, Duke, Orange & Rockland.

[459] *E.g.*, TANC, Turlock, SMUD.

[460] *E.g.*, PSNM and Nebraska Public Power District.

[461] Proposed Pro Forma Network tariff section 9.7—System Reliability.

[462] The Final Rule pro forma tariff contains language allowing the transmission provider the discretion to interrupt firm transmission service in an emergency or other unforeseen condition in a manner suggested by these commenters. Section 11.6, Curtailment of Firm Service, of the Final Rule pro forma tariff provides:

However, the Transmission Provider reserves the right to interrupt, in whole or in part, firm Transmission Service provided under this Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its transmission system.

The reference to curtailments being allocated on a proportional (pro rata) basis addresses situations where multiple transactions could be curtailed to relieve a constraint.

service under the tariff to a transmission dependent utility that fails to curtail load as required may not be appropriate. As a result, we clarify that under network and point-to-point service, the transmission provider may propose a rate treatment (penalty provision) to apply in the event a customer fails to curtail load as required under the Final Rule pro forma tariff. Such proposals will be evaluated on a case-by-case basis on compliance.

b. Curtailment Provisions for Non-Firm Service

Comments

A number of commenters seek clarification of the curtailment provision for non-firm service under the two tariffs. They note that economy purchases by the network customer are accorded a higher curtailment priority than non-firm service under the point-to-point tariff. However, under the point-to-point tariff there is no acknowledgement of this higher priority for network service. Curtailments for non-firm transmission service under the point-to-point tariff are simply based upon duration of service, without reference to a higher priority for network economy purchases.

A number of commenters, including Industrial Energy Applications, suggest that a price-based curtailment queue for non-firm transmission will facilitate economy energy deals in highly competitive wholesale power supply markets and allow the parties to directly address delivery risk through the pricing mechanism.

Blue Ridge argues that the final rule should provide equal curtailment priority for all types of non-firm transmission service. Utilities For Improved Transition argues that network customers should be able to transmit non-firm power imports under the network tariff with the same curtailment priority that is assigned to all other firm network uses of the transmission system.

A number of commenters note that the tariffs allow non-firm service to be interrupted only for emergency or reliability reasons or to provide firm service. These commenters contend that, under this requirement, curtailment of non-firm service is unlikely.[463] As a result, they believe that non-firm service is elevated to firm service. To remedy this situation, these commenters argue that transmission providers should have the ability to curtail non-firm service for any economic reason.

Commission Conclusion

We have clarified in the Final Rule pro forma tariff that a network customer's economy purchases have a higher curtailment priority than non-firm point-to-point transmission service.

A higher curtailment priority should be provided to network economy energy purchases for the reasons stated in *AES Power, Inc.*.[464] In that case, we recognized that the network transmission customer has already ''paid'' for the transmission of its economy purchases (*i.e.*, transmission that is used to substitute one resource for another on an as available basis) through its payment of a load ratio share of the system.

Many commenters oppose the point-to-point service provision allowing non-firm service to be interrupted only for emergency or reliability reasons or to provide firm service. Upon further consideration, we agree that this provision is too narrow. Accordingly, the Final Rule pro forma tariff is revised to allow the transmission provider to curtail non-firm service for reliability reasons or economic reasons (*i.e.*, in order to accommodate (1) a request for firm transmission service, (2) a request for non-firm service of greater duration, (3) a request for non-firm transmission service of equal duration with a higher price, or (4) transmission service for economy purchases by network customers from non-designated resources.). However, all curtailments must continue to be made on a non-discriminatory basis including curtailments of the transmission provider's own non-firm uses of the transmission system under the tariff. A firm point-to-point customer's use of transmission service at secondary points of receipt and delivery will continue to have the lowest curtailment priority.

4. Specific Tariff Provisions

a. Network and Point-to-Point Customers' Uses of the System

Comments

Generally, transmission providers argue that the tariffs give too much flexibility to customers, while transmission customers argue that even more flexibility is required. The arguments are generally tied to pricing rather than technical problems with providing any level of service.

A common transmission provider argument is that the proposed firm point-to-point tariff provides a premium service comparable to network service, but at a lower rate. It has been suggested that either the flexibility to use non-firm service at secondary points of receipt and/or delivery at no additional charge under the point-to-point tariff be eliminated or that point-to-point customers should pay a premium price for such flexibility.[465] Transmission providers generally argue that flexible point-to-point service puts the transmission owner and the network customer at a competitive disadvantage. They assert that the point-to-point customer is able to use non-firm transmission to reach secondary receipt and delivery points for both sales and purchases, but the network customer may use only non-firm transmission to reach secondary points for purchases. Thus, they argue, the flexible point-to-point users can sell non-firm power with a small or even no transmission component (because the underlying transmission is effectively free). Electric Consumers Alliance and Cajun believe that the owner and network customer competing for that sale should not be charged for the identical transaction. Absent a change to the point-to-point tariff, a number of transmission providers and state commissions (including Midwest Commissions) argue that to provide balance to the tariffs, the network tariff should permit the network customers to have non-firm transmission to secondary receipt and delivery points at no additional charge for both purchases and sales within its load-ratio transmission entitlement. Utilities For Improved Transition refers to this proposed network tariff modification as ''headroom.''

CCEM opposes the headroom concept, arguing that ''free'' use of capacity will give transmission providers an unfair competitive advantage. CCEM also cites Order No. 636 in support of its position.

Conversely, a number of customer groups believe the point-to-point tariff should be made more flexible by broadly defining the concept of points of receipt and delivery. They argue that all points of connection between the transmitting utility and the purchasing utility should be treated as a single point of delivery (POD) or point of receipt (POR).[466] In this manner, a customer would not have to pay for every point of receipt or point of delivery, but could select a contract demand level of service. The customer could then use the service at multiple

[463] *E.g.*, Florida Power & Light Company, Southern California Edison Company.

[464] 69 FERC ¶ 61,145 at 62,300 (1994) (proposed order), 74 FERC ¶ 61,220 (1996) (final order).

[465] *E.g.*, EEI, Utility Working Group, SoCal Edison.

[466] *E.g.*, Arkansas Cities, NRECA.

points without incurring separate reservation charges for each point.

A number of commenters contend that the Commission should not force specific tariffs on public utilities in the Pacific Northwest due to their unique status.[467] In particular, NWRTA recommends that the final rule recognize that the Pacific Northwest's integrated transmission system, including large components owned by non-public utilities, was constructed to support a unique region-wide hydroelectric-dependent generating system. NWRTA recommends that the final rule be sufficiently flexible to accommodate these unique characteristics without prejudicing the interests of users or providers of transmission services.

Similarly, Public Generating Pool states that the NOPR pro forma network tariff departs from the status quo arrangements in the Northwest and is generally unworkable because generation is usually remote from the control area serving the network load and because BPA, which does not have a typical service territory, dominates the regional transmission market. Public Generating Pool suggests that the Commission require, and the region develop, a ''generation integration'' transmission tariff that would offer network-type service to a source or sources of generation unbundled from the ''network services'' designed to integrate load. Similar contract demand network tariffs have already been proposed by some IOUs.

Commission Conclusion

We will not allow network customers to make off-system sales within the load-ratio transmission entitlement at no additional charge. Commenters have raised no new arguments to persuade us to do so. The primary purpose of network service is to integrate resources to serve loads. Use of transmission by network customers for non-firm economy purchases, which are used to displace firm network resources, must be accorded a higher priority than non-firm point-to-point service and secondary point-to-point service under the tariff. Off-system sales transactions, which are sales other than those to serve a network customer's native load, must be made using point-to-point service. They can be made on either a firm or non-firm basis.

A large number of transmission providers support the ''headroom'' concept, arguing that without it the flexible point-to-point service puts them at a competitive disadvantage. This would be true if a utility serving load were required to use network service exclusively. However, we do not require any utility to take network service to integrate resources and loads. If any transmission user (including the public utility) prefers to take flexible point-to-point service,[468] they are free to do so. Any point-to-point customer may take advantage of the secondary, non-firm flexibility provided under point-to-point service equally, on an as-available basis.

b. Minimum and Maximum Service Periods

Comments

Commenters raise issues regarding the minimum term of one hour for firm point-to-point service. Their concerns center on price and priority. Transmission providers point out that their native load customers pay the fixed cost of the transmission system every hour of the year. They argue that comparability is not achieved by permitting others to have service for one hour with equal priority to native load and other long-term customers. Others worry that the one-hour minimum term will: (1) Promote the selective use of the transmission system; (2) impair the ability of a utility to plan its system; and (3) adversely impact longer term transactions.

Tallahassee and KY Com are concerned that one-hour firm service may encourage speculative advance requests for service during the system peak day (Cajun refers to this as cream skimming). These commenters express concern that such requests could displace other valid transactions or constrain a corridor or interface to the detriment of network service or native load customers. Tallahassee proposes a one-day minimum term for firm service.[469]

East Kentucky is concerned that users of the transmission system could, under the Commission's proposed open-access rule, purchase short-term firm service during peak months in lieu of annual firm service to reduce expenses associated with the purchase of firm transmission service. By buying short-term firm service only during the peak months, an entity can significantly reduce its transmission expenses by purchasing non-firm service during off-peak months when the available transmission capacity far exceeds the demand on the transmission system. For this reason, some commenters request that short-term firm service be priced to generate revenues over the peak months equal to the charge for annual firm service.

Duke argues that, because all curtailments are equal, the addition of each one hour firm transaction will lower the reliability profile of native load customers and other customers with long-term commitments. It suggests that different classes of services be established that offer transmission customers the flexibility to obtain an intermediate level of transmission service (between native load firm and non-firm) for transactions of shorter duration.

On the other hand, some TDUs and power marketers support the one-hour minimum term. TAPS argues that transmission providers should not be permitted to restrict the availability of hourly, daily or weekly transmission service at reasonable prices, as some transmission providers have proposed in open access cases. Brazos supports a minimum duration of service equal to the minimum scheduling period of the transmission owner. Turning to the maximum term of service, Chugach objects to the imprecise requirement that transmission service be offered for a term equal to the life of a particular generation resource. Chugach, joined by VEPCO, suggests that the Commission require transmitting utilities to offer five-year terms (with longer contract terms by negotiated agreement).

Although BPA supports eliminating arbitrary term limitations and facilitating long-term resource commitments, it is concerned that the Commission's failure to specify a maximum term for firm transmission service (particularly where no specific resource is being wheeled) requires transmitting utilities to effectively sell off their transmission capacity to third parties. In BPA's view, such a requirement goes well beyond the intent of the Energy Policy Act.

PSE&G argues that the term limit for firm transmission service should be consistent with the transmission provider's planning horizon (*e.g.*, for PSE&G, 10 years), which will ensure comparability of firm third party customers with native load. According to ConEd, failure to specify a maximum term for service creates uncertainty for planning purposes. PECO believes that utilities should have the right to limit the term of service to either: (1) The expected useful life of facilities used in providing service; or (2) the term of permits and land rights needed for those facilities.

[467] *E.g.*, Public Power Council, Washington Water Power, NWRTA.

[468] *See* Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC ¶ 61,006 at 61,013 and n.70 (1996).

[469] *See also* VEPCO, CSW, NYSEG, WP&L.

Commission Conclusion

We will adopt a one-day minimum term for firm point-to-point service. The one-day minimum term for firm point-to-point service, along with modifications to the procedures for requesting firm point-to-point service, will moot a number of reliability concerns and allegations about possible ''cream-skimming.'' As discussed *supra*, firm service requests with longer durations of service will have bumping rights over shorter term firm service requests. Also, the one-day minimum will not disadvantage anyone because the transmission provider will be subject to the same one-day term for its firm point-to-point uses of the transmission system. Because of the longer-term nature of network service, it will be subject to a one-year minimum term.

We will not specify a maximum term for either point-to-point or network transmission service. However, we recognize the concerns raised by commenters that a commitment of uncertain duration makes planning difficult. Therefore, we will modify the tariff to require that an application for transmission service specify the length of service being requested. This will provide the transmission provider with the certainty it needs for planning and the transmission customer with the flexibility to request the service it needs.

c. Amount of Designated Network Resources

Comments

The NOPR pro forma network tariff specifies that a customer may designate only those resources that the customer owns or has committed to purchase pursuant to an executed contract. Transmission providers argue that there is a need for some limitation on the resources that network customers can designate to serve their loads. Otherwise, they assert, a utility would be required to incur costs (planning, constructing, and operating its transmission system) that are out of proportion to the customer's load and its share of the utility's cost of service. However, EEI, VEPCO, and Utilities For Improved Transition believe that the Commission's proposal to use a purchase obligation standard is too narrow, inflexible, and susceptible to manipulation. These IOU commenters argue that it could include very short-term obligations and contingent obligations to purchase. EEI suggests that the Commission should establish a minimum term so that a customer could not designate resources for which it has only a one-month contract. The principal problem VEPCO sees is that purchase obligations may not be clear. According to VEPCO, a transmission customer may claim an obligation when it has no substantial payment obligation and thus no economic deterrent to designating that purchase obligation as a potential resource to serve its loads. It alleges that the result is that the transmitting utility can be forced to tie up transmission capacity for service from a resource that may have little probability of being used; consequently, less capacity will be available for other uses. VEPCO further argues that, since upgrade costs are typically rolled in, the customer may not have a strong incentive to minimize transmission construction. EEI argues for system-specific limits based on capacity needs to serve the network loads reliably. Alternatively, if the ''own'' or ''purchase'' provision is to be used, EEI contends that the customer should be required to have a significant and ongoing obligation to purchase power (*e.g.*, minimum one-year contracts that impose obligations on a first-call basis).

These IOUs also recommend that the Commission not decide on a single way to limit network resources. They note that proposals based on percentage limits (*e.g.*, 125%) subject to exceptions for reliability concerns may be a reasonable approach. According to these IOUs, the Commission should permit flexibility to develop not unduly discriminatory provisions until experience suggests which are the best ways to satisfy the objective. To prevent over-designating network resources, Missouri-Kansas Industrials suggest placing a limit of 200% of the subscriber's load.

Arkansas Cities supports limiting the definition of network resources to those that the customer owns or contracts for. It argues that this reasonably accommodates the planning process. Arkansas Cities argues that any type of percentage adder would unreasonably restrict the process.

ELCON states that virtually any issue regarding the nature of network service can be resolved by reference to the price of such service. According to ELCON, if a transmission customer seeks to incorporate unlimited (*i.e.*, unspecified) generation sources into its network load, the customer should pay a higher rate than a network customer that can identify a need for service to/from specified generating units.

A related issue is how interface capacity should be allocated between network customers and the transmission provider. IOUs generally argue that interface capacity should be allocated based upon the load ratio of the customers. Tariff customers generally argue that there should be no restriction on the amount of interface capacity that they may designate.

Commission Conclusion

We do not believe that a superior alternative has been suggested to our purchase obligation for limiting network resources. Accordingly, we will not change the limitation on the amount of resources a network customer may designate. A transmission provider taking network service to serve network load under the tariff also is required to designate its resources and is subject to the same limitations required of any other network customer.

Limiting the amount of resources to those that the customer owns or commits to purchase will protect a utility from having to incur costs that are out of proportion to the customer's load. The transmission provider's concern that the purchase limitation will result in excessive network resources is unfounded. A transmission customer, like a transmission provider, has an incentive not to oversubscribe its capacity requirements because the cost of excessive reserve margins will be prohibitive. Requiring a strict percentage limitation could distort the planning process by limiting the size of resource additions a transmission customer may undertake. Allowing discretionary exceptions to the percentage limit will inevitably lead to disputes and claims of discrimination.

With respect to the allocation of interface capacity under network service, we clarify that a customer is not limited to a load ratio percentage of available transmission capacity at every interface. A customer may designate a single interface or any combination of interface capacity to serve its entire load, provided that the designation does not exceed its total load.

d. Eligibility Requirements

Under the NOPR pro forma tariffs, the transmission provider and anyone who can file a section 211 request is eligible to request service.

Comments

In general, most commenters agree with the eligibility requirements. However, several IOUs argue that the tariffs should be modified specifically to preclude the use of the tariffs for retail wheeling.[470]

NIEP believes the eligibility provision should include all entities that not only generate power themselves, but also purchase power generated by others for

[470] *E.g.*, El Paso, Southern, NSP.

resale, including municipalities, federal entities with rights to purchase, and other entities with load but no generation resources.

Power Marketing Association and others argue that the network tariff should be modified to specifically allow service to marketers.

PacifiCorp argues that independent owners of generation resources should not be allowed to acquire network integration service directly. It suggests that, if the eligible utility does not have a load in the control area, the service sought is to accommodate off-system sales, which is a point-to-point service.

Commission Conclusion

As we previously explained, a non-discriminatory open access transmission tariff must be made available, at a minimum, to any entity that can request transmission services under section 211 and to foreign entities.[471] Eligibility to take service is further discussed in Section IV.C.1.

e. Two-Year Notice of Termination Provision

Comments

Ohio Edison, Utilities For Improved Transition, LA DWP, and VEPCO believe that point-to-point transmission customers should not be allowed to terminate transmission service prior to the end of their contract term, especially in light of their reassignment rights. For network service, VEPCO, Florida Power Corp, Utilities For Improved Transition, and Duke believe that the notice of termination period should be at least five years, to coincide with the utility's construction horizon. In particular, VEPCO wants transmission customers terminating service prior to the end of the contract term to pay for network upgrades constructed for their benefit that would be stranded due to early termination of service.

CCEM supports a six-month notice of termination as appropriate for a term of service of one year or greater; any longer notice period would unduly limit a transmission customer's purchasing options.

NYSEG and EEI want the flexibility to negotiate a reasonable, mutually agreeable notice of termination period to recognize such things as the term of the contract and the amount of service at issue.

LEPA, VT DPS, and NorAm believe that written notice of termination should not be required for transactions of two years or less.

[471] *See* discussion in Section IV.C.1.

Commission Conclusion

We will delete the notice of termination provision from the tariff. We believe that commenters have raised a number of valid concerns about including the notice of termination provision. In particular, the notice of termination will have no effect on short-term service of less than two years. In addition, the two-year notice provision does not coincide with either a transmission provider's planning or construction horizon. Because we are eliminating the notice of termination provision from the tariff, transmission service will have to be reserved and paid for over the length of the contract term. Of course, by eliminating this tariff provision, we are not precluding parties from negotiating mutually agreeable terms for early termination on a case-specific basis. However, we note that point-to-point customers are able, under the reassignment provision, to resell unused transmission capacity.

f. Reciprocity Provision

In the NOPR, the Commission explained that it was requiring a reciprocity provision in the non-discriminatory open access transmission tariffs so that public utilities offering transmission access to others would be able to receive service from transmitting utilities that are not public utilities (*e.g.*, municipal power authorities and federal power marketing administrations that receive service under a public utility's tariff).

Comments

Reciprocity Requirement

The vast majority of the jurisdictional IOUs commenting on this issue favor a reciprocity requirement. In contrast, the non-jurisdictional transmission customers (primarily publicly-owned entities and cooperatives) generally oppose such a requirement. The few state commissions commenting on this issue generally support the stated goal of the reciprocity requirement, but question our legal authority to require it.[472] The few IPP and power marketer commenters that address this issue do not object to reciprocity if it does not apply to non-transmission owners.[473]

Several commenters believe that all transmission-owning utilities, whether public or investor-owned, must be required to provide open access service for a truly competitive wholesale power market to be realized.[474] Sierra states that specific legislation by Congress and/or state lawmakers may be necessary to ensure that currently non-public utilities comply with the Commission's open access requirements.

A number of commenters maintain that the Commission should enforce reciprocity by allowing public utilities to deny transmission service to non-public utility transmitting entities when reciprocal transmission service is not offered.[475]

Phelps Dodge and Otter Tail believe that non-public utility transmitting entities will continue their existing bundled service contracts indefinitely to avoid complying with the reciprocity requirement. Therefore, to promote transmission access through reciprocity, Phelps Dodge and Otter Tail suggest requiring the unbundling of existing contracts by a date certain to convert such contracts to transmission service agreements under the transmission provider's open access tariff.

A number of commenters argue that the Commission's only legal authority to impose a reciprocity requirement on non-public utilities is that provided by section 211 of the FPA.[476] Large Public Power and others suggest that mandating reciprocity is not necessary because the stated goals of the reciprocity requirement can be met by voluntary transmission access and through section 211 filings.

Many commenters do not oppose reciprocity if it is modified to incorporate the protections present in sections 211 and 212 and the benefits available under sections 205 and 206.[477] TDU Systems explains that section 211 contains a number of protections, *e.g.*, transmitting utilities cannot be required to provide transmission service if such service impairs their ability to provide reliable service, disrupts existing contracts with entities seeking service, or is inconsistent with state law regarding retail marketing areas. It also notes that section 212 contains rate provisions that protect a non-public utility transmission provider from being forced to provide electric service at a non-compensatory rate. Seminole EC argues that, without section 205/206 rights, non-public utilities cannot adjust their tariffs or challenge tariff provisions that they believe should not apply to them.

Several commenters also suggest that, without sections 211, 212, and 205 rights and protections, reciprocity

[472] *E.g.*, IL Com, KY Com, VT DPS, GA Com.

[473] *E.g.*, CCEM, CA Energy Co.

[474] *E.g.*, Sierra, MidAmerican, Tucson Power.

[475] *E.g.*, Puget, Sierra, NSP.

[476] *E.g.*, NRECA, Omaha Public Power District, Dairyland, AEC & SMEPA, PA Com, IL Com, TDU Systems.

[477] *E.g.*, NRECA, SC Public Service Authority, Seminole EC, TDU Systems.

provisions allow the transmission provider to deny transmission based on its own determination of the transmission customer's attempt to comply with reciprocity, which SC Public Service Authority contends is letting the ''fox guard the henhouse.'' TAPS states that in no event should the claimed lack of reciprocity constitute grounds for refusal to offer a service agreement, or unilateral denial, delay or termination of service. TAPS, and other cooperative, municipal, and public power commenters suggest that some procedure must be developed to bring reciprocity disputes before the Commission. Wisconsin Municipals argues that this provision should be modified, claiming that a customer's receipt of a revenue credit for transmission facilities it contributes to the transmission provider's system should satisfy the reciprocity requirement.

Rather than filing tariffs with the Commission, Dairyland suggests allowing cooperatives that are not public utilities to file a compliance transmission tariff with the Rural Utilities Service (RUS) as it relates to the issue of reciprocity, thereby affording non-jurisdictional cooperative utilities rights and privileges similar to those afforded jurisdictional utilities.

Application of Reciprocity Requirement

Several commenters argue that reciprocity should apply to both the seller and purchaser engaged in a transaction under an open access tariff to ensure that: (1) Transmission customers cannot avoid their reciprocity obligation by requesting service through an agent that owns no transmission facilities; (2) a generator cannot take transmission service in order to sell power to a non-jurisdictional entity, thereby allowing the non-jurisdictional entity to escape the reciprocity provision, and (3) a buyer cannot take service in order to purchase power from a non-jurisdictional entity, thereby allowing the entity to escape the reciprocity requirement.[478]

Entergy also is concerned that reciprocity can be evaded through the use of power marketers. Therefore, Entergy proposes that, if the transmission customer is neither the producer, transmitter, nor distributor of the power and energy to be transmitted, but instead acts as a marketer, the marketer must designate an electric utility that either produces, transmits, or distributes such power and energy as being subject to the requirement to provide comparable service.

CCEM and NIEP support the reciprocity provision because they apply only to transmission owners. CCEM and NIEP contend that non-transmission-owning customers should not be required to procure transmission capacity or hire a proxy solely to meet a reciprocity requirement.

In contrast, CA Energy Co insists that the reciprocity provisions of the proposed tariffs must be amended to clarify that IPPs can obtain access even if the IPPs own no transmission assets. CA Energy Co argues that the Commission must exempt IPPs from the reciprocity requirement if IPPs are to be assured equal access and thus remain effective competitors.

Publicly-Owned Entities

Publicly-owned entities argue that they differ from IOUs and cannot provide completely reciprocal services.[479] LPPC identifies a number of differences between publicly-owned utilities and IOUs, such as: the publicly-owned utilities' use of tax-exempt debt, which could be jeopardized if they are required to make their transmission systems available for private use; restrictions on the rate-setting methods publicly-owned utilities can use; and statutory restrictions on the services publicly-owned utilities can offer.[480] LPPC asks that the reciprocity provision be dropped or changed to recognize these differences.[481] It argues that the purposes of the NOPR are met by transmission tariffs voluntarily offered by its members that generally meet the standard of open access.

NE Public Power District notes that to the extent that the Commission requires cost-based rates, the Commission must recognize that publicly-owned utilities do not establish rates in the same manner as IOUs; for example, NE Public Power District does not include depreciation or return on equity as costs in its rates, nor does it pay federal income taxes. It suggests that the Commission should not apply a one-size-fits-all approach to pricing transmission service, should consider the special circumstances of publicly-owned utilities in exercising its authority under section 212, and should give publicly-owned utilities the opportunity for an evidentiary hearing before requiring them to adopt rate-setting conventions that are appropriate for public utilities.[482]

CAMU asserts that the tax-exempt financing of government bodies may be jeopardized due to limitations on the private use of facilities that are financed through tax exempt bonds.[483] It suggests that a solution may be to impute the cost of capital based on the average cost of all area utilities. Wisconsin Municipals says that the Commission should seek an opinion from the IRS regarding whether reciprocal use would jeopardize tax-exempt status; if it is determined it would, the owner of the transmission facilities should be allowed to recover any increased costs associated with the loss of tax-exempt status.[484]

DE Muni is concerned that a utility may ''impose'' the open access tariffs on a non-public utility customer such as a municipal system and then demand reciprocal access to that customer's transmission facilities to serve the municipal's retail customers.

San Francisco argues that there is no legal authority in the FPA or case law to impose the open access requirement on non-public utility entities. Moreover, San Francisco is concerned that the reciprocity requirement may impair its ability to deliver its own power pursuant to the requirements of the Raker Act.

Salt River opposes the reciprocity provision because it could ''administratively vest discriminatory market power in FERC jurisdictional public utilities.'' Salt River further argues that ''duly adopted open access transmission tariffs or rate schedules of publicly-owned utilities should be presumed to satisfy FERC's reciprocity requirement, and the legislative action of the publicly-owned utility's ratemaking body should be given deference in a dispute brought before FERC relating to the tariff or rate schedule.''

Public Generating Pool argues that a non-public utility transmission customer should not have to provide the same service a public utility provides. It argues that a publicly-owned entity may lack the resources to provide the high level of service a public utility can provide.

Tallahassee seeks clarification that reciprocity does not mean that investor-owned utilities can require municipal utilities to offer services that are *identical* to those offered by the

[478] *E.g.*, EEI, Consumers Power, Montana-Dakota Utilities, CSW, Duke, BPA.

[479] *E.g.*, Blue Ridge, SMUD, LPPC, Salt River, Oglethorpe.

[480] *See also* Omaha PPD, Salt River, MEAG, TAPS.

[481] *See also* Omaha PPD.

[482] *See also* Heartland.

[483] *See also* Wisconsin Municipals, Omaha PPD, Salt River, MEAG, MMEWC, NE Public Power District.

[484] *See also* TAPS.

investor-owned utilities. It argues that it is not practical to require small utilities to provide all of the services bigger utilities provide and that legal obligations imposed on municipal utilities may interfere with their ability to provide certain types of open access provisions. Tallahassee concludes that reciprocity should be equated with comparability (the transmission user must offer service that is comparable to the service it offers to itself).

TANC asks for clarification and suggests various changes to the reciprocity provision. It asks whether the reciprocity requirement will apply to it, since it is part owner of a transmission facility (the California Oregon Transmission Project (COTP)) but has contractually dedicated its entitlement to use of this facility to its members. It argues that if the requirement does apply, its obligation should be limited to the member's share of TANC's entitlement. TANC also asks whether when it receives transmission service on behalf of a member, that member's non-COTP transmission facilities must be made available to the transmission provider. If that is the case, TANC asks what voltage level of facilities must TANC and its members make available? TANC believes that if a TANC member independently requests transmission service from a utility, that member would be obligated to make reciprocal service available to the utility on the share of the COTP that member ''controls'' through TANC's entitlement. TANC argues that neither TANC and its members nor TANC and its COTP co-owners should be treated as ''affiliates'' under the proposed reciprocity provision. It argues that the comparable service tariff it must provide as a member of the Western Regional Transmission Association should satisfy the reciprocity requirement.

TANC also asks for clarification as to how the reciprocity provision would be administered. A non-public utility cannot file a tariff with the Commission, so presumably it and the public utility from which it wants transmission service would negotiate; if, however, the public utility does not agree that reciprocal service is being offered, it will deny access to its transmission facilities, and the non-public utility would have to come to the Commission to resolve the dispute. SC Public Service Authority expresses a similar concern. It argues that the reciprocity provision will prevent non-public utilities from obtaining comparable access. The public utility from which the non-public utility wants access will be able to delay access by claiming that the reciprocity provision is not satisfied. Even the possibility of such a delay may discourage customers from contracting with non-public utilities. SC Public Service Authority suggests that this problem can be fixed by allowing non-public utilities to file comparable access tariffs with the Commission.

NE Public Power District asserts that while government-owned utilities are subject to limited regulation under sections 211–213 of the FPA, ''that limited grant of jurisdiction cannot be transmuted into amenability of state- and municipally owned utilities to the sort of detailed regulation that the NOPR would impose through requiring insertion of so-called 'reciprocity' clauses in the transmission tariffs of jurisdictional public utilities, by inviting the filing of 'class' § 211 applications, or by making adherence to the rules emerging from the NOPR proceeding an automatic requirement for utilities that are subject to a section 211 application.''

NE Public Power District explains that it has pending before the Commission a proceeding in which it has taken the position that it is not subject to the Commission's jurisdiction. (citing Docket No. TX95–3–000).[485] NE Public Power District also argues that it would be unconstitutional under the Tenth Amendment and the Guarantee Clause of the United States Constitution for the Commission to assert jurisdiction. It further argues that the proposed regulations would constitute an unfunded Federal mandate within the meaning of the Unfunded Mandates Reform Act of 1995 and that the Commission has not followed the requirements of that Act.

NE Public Power District explains that under Nebraska law it is prohibited from granting or conveying to any private entity any interest or control of any of its property or facilities, and section 211 does not authorize the Commission to order wheeling for an end-user or to replace a contractual wholesale sale. Thus, it argues that the Commission does not have authority to use mandatory reciprocity clauses to obtain compliance with a policy it has no right to impose directly. (citing *Sunray* and *AGD*). NE Public Power District also questions whether the Commission may lawfully declare exclusive-use provisions invalid under the *Sierra-Mobile* doctrine without conducting a proceeding under section 206 with regard to each specific facility and making the necessary findings.

Salt River responds to complaints that public power entities have a competitive advantage, due to subsidies and preferences, over investor-owned utilities:

> This Commission is not the appropriate forum and this proceeding is not the appropriate proceeding to consider the investor-owned utilities' ''level playing field'' complaint as it relates to public power, and the Commission should reject any suggestion that it do so.[486]

Cleveland urges the Commission not to address in the NOPR proceeding either congressional policy as reflected in the tax laws or the propriety of other long-standing federal statutes in considering complaints that publicly-owned entities receive subsidies from the government that IOUs do not. It points to three tax breaks available to IOUs: (1) Investment tax credits; (2) deferred taxes resulting from different book and tax depreciation; and (3) use of tax-exempt financing in certain circumstances.

NRECA/APPA argues that the Commission should not, as requested by EEI, address alleged ''undue'' subsidies received by consumer-owned utilities and delve into such subsidy issues as municipal financing policy, rural electrification and development policies, and the merits of privatizing the federal power marketing administration. NRECA/APPA alleges that these are complex issues that are within the domain of other federal agencies.

G&T and Distribution Cooperatives

NRECA explains that under Dairyland Power Cooperative,[487] the Commission does not have jurisdiction over cooperatives that have REA/RUS loans.[488] NRECA further explains that rural electric cooperatives are exempt from federal taxation only if 85 percent of their revenues are derived from their members and open access could jeopardize their tax relief.[489] RUS notes that while the Energy Policy Act expanded the Commission's authority to order transmission access, it did not

[485] We note that the application in Docket No. TX95–3–000 by Municipal Energy Agency of Nebraska was withdrawn on November 16, 1995.

[486] Salt River Reply Comments at 2. *See also* NCMPA.

[487] 37 FPC 12, 37 FPC 495 (1967), *aff'd sub nom.* Salt River Project v. FPC, 391 F.2d 470 (D.C. Cir.), *cert. denied,* 393 U.S. 857 (1968).

[488] *See also* Basin EC, Big Rivers EC (citing *Golden Spread,* 39 FERC ¶ 61,322, *reh'g denied,* 40 FERC ¶ 61,348 (1987)), RUS (asserting that RUS has exclusive authority over rural power cooperatives that have RUS loans).

[489] *See also* McKenzie EC, NW Iowa Cooperative, TDU Systems, RUS (asserting that if cooperative voluntarily gives up its tax exempt status, the Commission should allow the related tax expense to be included in the rates charged to the non-member customers only), Brazos, Tri-State G&T, TAPS.

amend the Rural Electrification Act (RE Act) so as to curtail the plenary powers of RUS to carry out a program of rural electrification.

Citing various cases, Brazos says that the Commission must be mindful of the purposes of the RE Act and, if available transmission on Brazos is taken for use by third parties, ''a question remains as to the capacity of the remaining portions of the system to function with 'decent service and at decent rates.' '' [490]

Various rural electric cooperatives state that the Commission must recognize that consumer-owned electric utilities are very different from investor-owned utilities.[491] Mor-Gran-Sou EC is concerned that the final rule will have a detrimental impact on rural areas, just as it believes deregulation of the banking industry, airline industry and telecommunications industry has had.

Many cooperatives request that the term ''affiliates'' be defined: (1) To apply only to corporate ''affiliates'' over which the transmission customer exercises legal control; and (2) to exclude the distribution cooperative members of a generation and transmission (G&T) cooperative.[492] Seminole EC explains that a G&T is a cooperative formed by a group of distribution cooperatives; therefore, a G&T has no legal powers to require action by its member cooperatives. In fact, according to Seminole EC, the distribution cooperatives govern the G&T.

Similarly, TDU Systems notes that the term ''affiliates'' could be construed to apply to a joint action agency and its municipal and cooperative members. TDU Systems point out that a joint action agency, itself a creature of statute, may not have the power to require its members to provide transmission service.

AEC & SMEPA contends that including the transmission customer's affiliates in the reciprocity obligation is broader than the obligation of the transmission provider, which does not include transmission service by the provider's affiliates. AEC & SMEPA suggests that either: (1) The transmission provider's affiliates should be included in the basic obligation to provide transmission service; or (2) the reciprocity provision should delete the reference to affiliates of the transmission customer.

NRECA comments that it is unclear whether ''facilities owned or controlled by the transmission customer'' include transmission contracts. NRECA believes that transmission contracts cannot be included in this definition, at least as applied to ''transmitting utilities'' under sections 211 and 212.

Transmission Provider

Seminole EC questions whether the requirement to offer ''open access'' service requires reciprocal service to be provided solely to the transmission provider or an open access tariff available to any and all qualified applicants. Seminole EC and NRECA request that the Commission adopt the former interpretation in the final rule.

In contrast, Tucson Power and Phelps Dodge believe that, if a non-public utility transmitting entity chooses to take service under any open access tariff, such access should be conditioned on its own agreement to provide comparable service to *all* eligible customers under an open access tariff.

Tucson Power believes that, without such access to all eligible customers, reciprocity will fail to achieve true ''comparability.'' Tucson Power explains that reciprocal transmission service would appear to be limited by the terms of the specific original request for transmission. For example, Tucson Power fears that a non-jurisdictional entity requesting 25 MW of point-to-point firm service could argue that its reciprocal transmission obligation is limited to the same 25 MW of point-to-point firm service for an equivalent duration. Tucson Power argues that such a limitation on providing reciprocal service would prove useless. Further, Tucson Power believes that reciprocity should be interpreted to require a non-public utility entity to expand or upgrade facilities to meet the transmission requests of all eligible entities and should contain the same pricing provisions as applied in this proceeding for jurisdictional utilities.

Seminole EC questions whether the reciprocity requirement to provide ''comparable'' service to the transmission provider simply means offering the same *kind* of service to the transmission provider that the transmission customer receives (i.e., network, firm point-to-point, or non-firm).

NRECA claims that the reciprocity requirement should not be construed to impose on non-public utilities an unreasonable obligation to build. Seminole EC adds that an unreasonable obligation to build could effectively preclude requests for tariff service; the transmission customer could be better off litigating a section 211 request rather than accepting the obligation to undertake a massive construction program.

Commission Conclusion

We conclude that it is appropriate to require a reciprocity provision in the Final Rule pro forma tariff. This provision would be applicable to all customers, including non-public utility entities such as municipally-owned entities and RUS cooperatives, that own, control or operate interstate transmission facilities and that take service under the open access tariff, and any affiliates of the customer that own, control or operate interstate transmission facilities. Any public utility that offers non-discriminatory open access transmission for the benefit of customers should be able to obtain the same non-discriminatory access in return.

In the NOPR, we explained that the reciprocity provision would ''requir(e) any user or agent of the user of the tariff that owns and/or controls transmission facilities to provide non-discriminatory access to the tariff provider.'' [493] We wish to clarify that, in stating that a user must provide non-discriminatory access to the tariff provider, we intend that reciprocal service be limited to the transmission provider. However, in situations in which a non-public utility is a member of an RTG or a power pool, it also would have to provide service to the other members of the RTG or power pool. We do not believe it is appropriate to expand the reciprocity condition beyond these situations at this time because, as discussed further below, the IRS currently is evaluating its tax-exempt financing regulations in light of competitive changes in the industry.

We are aware that many non-public utilities are very willing to offer reciprocal access, and that some are willing to provide access to all eligible customers through an open access tariff. However, they are fearful that a public utility may deny service based simply on a claim that the open access tariff offered by a non-public utility is not satisfactory. To assist these non-public utilities, we have developed a voluntary safe harbor procedure that should alleviate these concerns. Under this procedure, non-public utilities would be allowed to submit to the Commission a transmission tariff and a request for declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. We would post these requests on the Commission Issuance Posting System (CIPS) and would provide them with an NJ (non-

[490] Brazos Initial Comments at 6.

[491] *E.g.*, NW Iowa Cooperative, TDU Systems, Big Rivers EC, Mor-Gran-Sou EC, San Luis Valley REC, Tri-County EC; *see also* RUS, MEAG, Brazos.

[492] *E.g.*, NRECA, Cajun, AEC & SMEPA, Seminole EC, TDU Systems.

[493] FERC Stat. & Regs. at 33,050.

jurisdictional) docket designation. If we find that a tariff contains terms and conditions that substantially conform or are superior to those in the Final Rule pro forma tariff, we would deem it an acceptable reciprocity tariff and would require public utilities to provide open access service to that particular non-public utility.[494] In order to find that a non-public utility's tariff is consistent with our comparability standards, we would need sufficient information to conclude that the non-public utility's rate is comparable to the rate it charges others. In addition, once we find that a tariff is an acceptable reciprocity tariff, an applicant in a section 211 case against a non-public utility would have the burden of proof to show why service to the applicant under the same terms as the reciprocity tariff is not sufficient and why a section 211 order should be granted.

The safe harbor procedures that we have outlined above would be purely *voluntary* for non-public utilities. The procedures are intended to provide non-public utilities an opportunity to confirm that they are willing to provide comparable transmission service. If, however, a non-public utility chooses not to seek a Commission determination that its tariff meets the Commission's comparability standards, a public utility could refuse to provide open access transmission service only if such denial is based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements.

In addition to the safe harbor procedures, we note that a non-public utility that is a member of an RTG can meet our comparability standards through the RTG, and can provide an open access tariff that meets our comparability standards by filing a tariff with the administrator of the RTG.[495] Similarly, a non-public utility that is a member of a power pool could meet our comparability standard if the power pool adopts a joint pool-wide open access tariff.

Some commenters have challenged the Commission's jurisdiction to require any non-public utility that takes jurisdictional service to provide reciprocal non-discriminatory transmission services and to unbundle its rates. We are not requiring non-public utilities to provide transmission access. Instead, we are conditioning the use of open access services on an agreement to offer open access services in return. Non-public utilities can choose not to take service under public utility open access tariffs and can instead seek voluntary service from the public utility on a bilateral basis.

In response to arguments raised by publicly-owned utilities and cooperatives, we are not prepared to revise or eliminate the reciprocity condition. Our reason is simple and compelling. We are undertaking this Rule and imposing significant responsibilities on public utilities to ensure the Nation's transmission grid is open and available to customers seeking access to the increasingly competitive commodity market for electricity. While we do not have the authority to require non-public utilities to make their systems generally available, we do have the ability, and the obligation, to ensure that open access transmission is as widely available as possible and that this Rule does not result in a competitive disadvantage to public utilities. Non-public utilities, whether they are selling power from their own generation facilities or reselling purchased power, have the ability to foreclose their customers' access to alternative power sources, and to take advantage of new markets in the traditional service territories of other utilities. While we do not take issue with the rights these non-public utilities may have under other laws, we will not permit them open access to jurisdictional transmission without offering comparable service in return. We believe the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the non-public utility seeks to take advantage of open access on a public utility's system. However, we recognize that Congress has determined that certain entities in the bulk power market can utilize tax-exempt financing by issuing bonds that do not constitute ''private activity bonds'' [496] or by financing facilities with ''local furnishing'' bonds.[497] In both circumstances, Congress has entrusted the Internal Revenue Service (IRS) with the responsibility for implementation and for determining what uses of the facilities are consistent with maintaining tax-exempt status for bonds used to finance such facilities. It is not our purpose to disturb Congress's and the IRS's determinations with respect to tax-exempt financing.

We are encouraged that the IRS is presently reconsidering its private activity bond regulations in light of, among other things, the changing circumstances in the electric industry, including this proceeding.[498] We are hopeful that the IRS in its rulemaking will, to the maximum extent possible, remove regulatory impediments that limit the ability of industry participants to provide reciprocal open access service. Until that occurs, however, we believe we must ensure that the reciprocity requirement will not be used to defeat tax-exempt financing authorized by the Congress. Therefore, we clarify that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities.[499] If a non-public utility has sought a declaratory order on a voluntarily-filed tariff, we request that it identify the services, if any, that it cannot provide without jeopardizing the tax-exempt status of its financing.[500]

We believe, given the fact that the IRS is currently examining these issues, that our policy in this regard is appropriate for the time being. After the IRS acts, we will reexamine our policy to ensure that the reciprocity requirement is applied broadly to achieve open access without jeopardizing tax-exempt financing.

With respect to local furnishing bonds, which are available to a handful of public utilities, we note that Congress, in section 1919 of the Energy Policy Act, amended section 142(f) of the Internal Revenue Code to provide that a facility shall not be treated as failing to meet the local furnishing requirement by reason of transmission services ordered by the Commission under section 211 of the FPA if ''the portion of the cost of the facility financed with tax-exempt bonds is not greater than the portion of the cost of the facility which is allocable to the local furnishing of electric energy.'' [501] San Diego G&E has included in its existing transmission tariff a provision

[494] Public utilities would also be required to provide service during the pendency of any request for declaratory order. Otherwise, public utilities could continue to delay providing service.

[495] *See, e.g.,* Southwest Regional Transmission Association, 73 FERC ¶ 61,147 at 61,414 (1995).

[496] *See* 26 U.S.C. 141.

[497] *See* 26 U.S.C. 142.

[498] Definition of Private Activity Bonds, 59 FR 67658 (December 30, 1994), Proposed Rules (to be codified at 26 CFR pt. 1).

[499] The same would be true in the case of a G&T cooperative that is a tax-exempt entity under section 501(c)(12) of the Internal Revenue Code (26 U.S.C. 501(c)(12)) that would risk loss of tax-exempt status if more than 15 percent of its revenues are derived from business with non-members. We clarify that reciprocal service will not be required if providing such service would jeopardize the G&T cooperative's tax-exempt status.

[500] A tariff offered by a non-public utility transmission provider to satisfy the reciprocity requirement may include a provision permitting the transmission provider to refuse service if providing such service would jeopardize its tax-exempt status or the tax-exempt status of its bonds. The non-public utility could file a declaration to this effect in an NJ docket.

[501] 26 U.S.C. 142(f)(2)(A).

that provides that, if it appears that the provision of transmission service would jeopardize the tax-exempt status of any local furnishing bonds used to finance its facilities, San Diego G&E will not contest the issuance of an order under section 211 of the FPA requiring the provision of such service, and will, within 10 days of receiving a written request by the applicant, file with the Commission a written waiver of its rights to a request for service under section 213(a) of the FPA and to the issuance of a proposed order under section 212(c).[502] We believe such a provision is necessary and appropriate so that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime. Accordingly, we will require any public utility that is subject to the Open Access Rule that has financed transmission facilities with local furnishing bonds to include in its tariff a similar provision.[503]

In addition, in response to arguments raised by cooperatives and joint action agencies, we agree to limit the reciprocity requirement to corporate affiliates. If a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, would be required to offer transmission service. However, if a member distribution cooperative itself receives transmission service from the transmission provider, then it (but not its G&T cooperative) must offer reciprocal transmission service over its interstate transmission facilities.

Finally, a non-public utility, for good cause shown, may file a request for waiver of all or part of the reciprocity requirement. We would apply the same criteria we will use to determine whether to grant a waiver of all or part of the Final Rule's requirements for public utilities that request waiver.

The reciprocity requirement will also apply to any entity that owns, controls or operates transmission facilities that uses a marketer or other intermediary to obtain access. For example, if a municipal purchases power from a marketer that also arranges for the transmission of the power through a public utility open access tariff to the municipal, the municipal would need to meet our reciprocity requirements. We point out here that we have established a procedure, set out in Section IV.K.2., for small public utilities to request a waiver from some or all of the requirements of the Rule. We would apply the same criteria to waive the reciprocity condition for small non-public utilities.

g. Miscellaneous Tariff Modifications

(1) Ancillary Services

The pro forma tariff, attached as Appendix D, incorporates conforming revisions consistent with the determinations discussed in Section IV.D.

(2) Clarification of Accounting Issues

Comments

A number of commenters generally assert that, as presently configured, the Commission's Uniform System of Accounts does not support the proposed stranded cost and open access policies set forth in the NOPR. They urge the Commission to open a separate docket to address these accounting issues and bring together all parties to properly resolve them. More specifically, commenters ask whether certain of the requirements outlined in the NOPR pro forma tariffs would require changes to the Uniform System of Accounts. In particular, commenters are concerned that the recording of costs and revenues related to ancillary services, facilities studies, and system impact studies would require the creation of new accounts under the Uniform System of Accounts. In addition, commenters raise questions about the procedures transmission providers would have to follow for recording the costs for their own use of the system. Commenters also indicate that the Commission's accounting requirements may not be adequate to provide fully for the recognition of stranded costs as contemplated in the NOPR.

Commission Conclusion

The Final Rule will result in significant changes in the way public utilities conduct business. This will create needs for financial information that are different from those that the Commission and others found necessary in the past. The Commission believes that the accounting guidance discussed *infra* will be sufficient to provide the financial information needed for regulatory purposes in light of this Rule. Therefore, we will not institute a separate proceeding to propose changes to our Uniform System of Accounts at the present time. We recognize, however, that the industry is in an early stage of transition to an environment in which truly comparable transmission services will be provided to all wholesale users. If, after gaining additional experience, it becomes apparent that more guidance is needed, additional guidance can be provided at that time through issuance of accounting interpretations, guidance letters, or a notice of proposed rulemaking to change our accounting regulations.

Many of the accounting concerns expressed by commenters were addressed in the Chief Accountant's January 26, 1996 guidance letter. We offer the following additional clarifications on the Final Rule pro forma tariff requirements and certain other accounting issues related to the Final Rule.

(a) Transmission Provider's Use of Its System (Charging Yourself)

The purpose of functional unbundling is to separate the transmission component of all new transactions occurring under the Final Rule pro forma tariff, thereby assisting in the verification of a transmission provider's compliance with the comparability requirement. For example, if a transmission provider makes an off-system power sale, functional unbundling requires that the revenues received from that third-party customer be unbundled into specific transmission and production components. The transmission component of the revenues would be the product of the amount of transmission capacity used in making the sale and the applicable rate. With respect to off-system sales, the transmission provider would look to operating revenue accounts those revenues received from the customer to whom it made the off-system sale. We will require that the transmission service component and energy component of those revenues be recorded in separate subaccounts of Account 447, Sales for Resale.

(b) Facilities and System Impact Studies

Comparability mandates that to the extent a transmission provider charges transmission customers for the costs of performing specific facilities or system impact studies related to a service request, the transmission provider also must separately record the costs associated with specific studies undertaken on behalf of its own native load customers, or, for example, for making an off-system sale. Utilities choosing this method of recovering the cost of specific studies must keep detailed expense records pertaining to each specific study. We will require utilities to record the cost of such studies that are properly includable in the determination of net income for the

[502] *See* San Diego Gas & Electric Company, Docket No. ER96–43–000, Pro-Forma Point-to-Point Transmission Service Tariff, section 4.6(d); Network Transmission Service Tariff, section 4.7(d).

[503] *See* Appendix D, Pro Form Open Access Transmission Tariff, Section 5.

period in a separate subaccount of Account 566, Miscellaneous Transmission Expenses. We note, however, that not all studies performed by a transmission provider will benefit only a single customer. To the extent a transmission provider performs a system impact study that is useful in providing service to all transmission customers, the costs should be allocated to all customers.

(c) Ancillary Services

To ensure comparable transmission access a transmission provider is obligated to provide, or offer to provide, certain ancillary services to the transmission customer. Also, the transmission provider may offer to provide other ancillary services to the transmission customer, as discussed in Section IV.D. A transmission customer is obligated to purchase certain ancillary services from the transmission provider.

Generation resources provide certain ancillary services, while transmission resources provide other ancillary services. Consequently, the costs of providing certain ancillary services are recorded in the transmission provider's power production expense accounts,[504] while others are recorded in the transmission provider's transmission expense accounts.

Some commenters suggest that there may be a need for revising the Uniform System of Accounts to better track the costs of providing discrete ancillary services. Other commenters believe that ancillary services are transmission-type services and suggested that the costs of generation-provided ancillary services be refunctionalized from power production expense to transmission expense.

Currently, the Uniform System of Accounts requires that costs incurred in providing ancillary services are recorded as power production or transmission expense depending upon which resource the transmission provider uses to supply the service. At this time, we are not convinced that the amounts involved or the difficulty associated with measuring the cost of ancillary services warrants a departure from our present accounting requirements. However, in calculating separate rates for specific ancillary services utilities must maintain sufficient records and cost support for the derivation of the rates. Additionally, we will specify that the revenues a Transmission Provider receives from providing ancillary services must be recorded by type of service in Account 447, Sales for Resale, or Account 456, Other Electric Revenues, as appropriate.

(3) Liability and Indemnification

Comments

A number of commenters addressed the liability and indemnification provisions of the proposed pro forma tariffs. Duke argues that the proposed language confuses and conflates the limitation on the Transmission Provider's and Customer's rights against each other if a force majeure event occurs, and the requirement of indemnification against claims by third parties.

EEI argues that the proposed indemnification provision is inappropriate because it applies both ways, that is, the Transmission Provider and Customer indemnify each other against third party claims arising on their own systems. EEI suggests that the provision, as written, could result in the utility being required to indemnify the customer against damages incurred if, for example, an individual pried open a transformer to steal materials and in the process was electrocuted. This concern was also voiced by Consolidated Edison, NYSEG, and Virginia Electric and Power Company. Consumer Power suggests that the best answer to this issue may be to leave the issue of allocation of risk to the contracting parties, to be resolved by negotiation when a Service Agreement is drawn up.

The Coalition for a Competitive Market, on the other hand, argues that the indemnification provision, as proposed, provides too much of a limitation of the Transmission Provider's liability, requiring gross negligence rather than simple negligence before the Transmission Provider can be held liable for damages to third parties arising from the Transmission Provider's actions.

Commission Conclusion

We agree with the commenters that these risk allocation provisions must be carefully drafted so that transmission providers and customers can accurately assess and account for their respective risks. The indemnification provision has now been broken into two parts. The first part is a force majeure provision which provides that neither the transmission provider nor the customer will be in default if a force majeure event occurs, but also provides that both the transmission provider and customer will take all reasonable steps to comply with the tariff despite the occurrence of a force majeure event. This protection against unexpected and unpredictable events is appropriately made available to both the transmission provider and transmission customer.

The second portion of the provision provides for indemnification against third party claims arising from the performance of obligations under the tariff. We have limited the indemnification portion of the provision so that it is now only the transmission customer who indemnifies the transmission provider from the claims of third parties. The customer is taking service from the transmission provider and may appropriately be asked to bear the risks of third-party suits arising from the provision of service to the customer under the tariff. We find that this new indemnification provision would be too strict if it required customers to indemnify transmission providers even in cases where the transmission provider is negligent. *See Pacific Interstate Offshore Company,* 62 FERC ¶ 61,260 at 62,733–34 (requiring amendment of indemnification provisions that required indemnification except in cases of ''gross negligence''). Accordingly, the revised provision provides that the customer will not be required to indemnify the transmission provider in the case of negligence or intentional wrongdoing by the transmission provider.

(4) Miscellaneous Clarifications

(a) Electronic Format

In the NOPR, we proposed that public utilities making Stage Two filings be required, in addition to the requirements specified in Part 35, to file copies of such filings on a diskette in ASCII format. We will now require that public utilities, in addition to complying with the requirements of Part 35, submit a complete electronic version of all transmission tariffs and service agreements in a word processor format, with the diskette labeled as to the format (including version) used, initially and each time changes are filed. After the initial compliance filing, utilities proposing changes to the Final Rule pro forma tariff terms and conditions must provide a detailed list of changes and, to the extent practicable, provide an electronic version that reflects changes in redline/strikeout format.

(b) Administrative Changes

A number of commenters request tariff modifications of an administrative nature. We have adopted many of these recommendations. Due to the nature of these changes, we feel that no further

[504] This discussion applies to vertically integrated transmission providers. It may not apply, for example, to a transmission-only company or an independent system operator.

explanation is necessary. The tariff modifications include the following:

Part I—Common Service Provisions

Description

- Added definition for Curtailment.
- Modified definition for Good Utility Practice.
- Added definition for Interruption.
- Added definition for Load Shedding
- Added definition for Long-Term Firm Point-to-Point Transmission Service.
- Added definition for Third-Party Sale.
- Modified provision for Interest on Unpaid Balances to include amounts placed in escrow.
- Modified provision for Customer Default to not require termination of service.
- Deleted contradictory language from the provision for Rights Under the Federal Power Act.
- Deleted references to Valid Request throughout the tariff.

Part II—Point-To-Point Transmission Service

Description

- Added language that multiple generating units at one site are considered one point of receipt.
- Changed the time to file an unexecuted service agreement from 10 days to 30 days.
- Changed the time to execute a service agreement from 30 days to 15 days.
- Deleted charge for scheduling changes.
- Deleted redundant language on study agreements.
- Changed standards for estimates from binding to good faith.
- Clarified that schedules of energy submitted to the delivering party will equal the schedules of energy submitted by the receiving party unless reduced for losses.
- Clarified that the term of non-firm point-to-point transmission service need not expire before the customer may submit another application for service.
- Added language for rate treatment in the instance when a customer uses more non-firm point-to-point transmission service than it has reserved.
- Clarified Deposit provision to permit return of deposit at expiration of service agreement rather than crediting the deposit against unspecified customer obligations under the tariff.
- Clarified provision for Yearly Extensions for Commencement of Service.
- Clarified provision for Reservation of Non-Firm Point-to-Point Transmission Service.
- Modified provision for customer Power Factor to permit mutually agreeable alternatives to maintaining a specified power factor.

Part III—Network Integration Transmission Service

Description

- Deleted redundant Direct Assignment provision.
- Added language to clarify that a transmission customer does not have to use the transmission provider's point-to-point transmission service if the sales to non-designated loads do not use the transmission provider's system.
- Modified Transmission Customer Redispatch Obligation to limit the redispatch obligation to reliability reasons.
- Deleted Member System requirement from network service.
- Deleted redundant General Conditions.
- Added provision to return application if customer does not remedy deficiency.
- Deleted redundant language for designating new network resources.
- Deleted redundant language for connecting new member systems.
- Deleted redundant language for new interconnection points.
- Added a 60 day period for initial applications consistent with the point-to-point service provision. (If applications during this period exceed available capacity, they are considered simultaneous requests and service will be decided based on a lottery.)
- Modified System Impact Study provision.
- Added 30 day turnaround for Facilities Study Agreement and changed estimates from binding to good faith.
- Deleted redundant language for adding new network resources.
- Added language for rate treatment in the instance when a customer fails to curtail or shed load.
- Deleted redundant language from Network Operating Committee.

H. Implementation

The Commission proposed in the NOPR a two-stage implementation process that would apply to all transmission-owning public utilities that do not have non-discriminatory open access transmission tariffs on file on the effective date of the final rule. As proposed in the NOPR, public utilities already in compliance with the rule would not be subject to the two-stage process.

In Stage One, the Commission proposed to put into effect tariffs for network and point-to-point services, which include ancillary transmission services. These tariffs would specify the minimum terms and conditions of service needed to eliminate undue discrimination, and were proposed to be effective 60 days after the effective date of the final rule. Because the proposed pro forma tariffs did not contain specific rates, the Commission proposed to itself establish, for each affected public utility, just and reasonable rates for network service, point-to-point service, and six identified ancillary services. These rates were to be incorporated into each utility's tariffs.

In Stage Two, which was to begin 61 days after the effective date of the final rule, parties would have been allowed to propose changes to the rates, terms, and conditions for service under utilities' transmission tariffs pursuant to sections 205 and 206 of the FPA.

Comments

The commenters are split on the two-stage implementation procedure proposed in the NOPR. Commenters in favor of the proposed procedure believe that a two-stage process is necessary to put basic open access tariffs in place without delay.[505] Florida Power Corp and NIEP state that a longer implementation procedure would create a discriminatory situation for utilities that have filed open access tariffs versus those that have not. Other commenters, however, contend that the proposed Stage One rates would be just and reasonable only as an interim measure; therefore, the period during which such rates are effective should be limited.[506]

Those commenters that oppose the two-stage implementation process do so for a variety of reasons.[507] Many transmission customers believe that Stage One rates will be much higher than the rates they pay now. Several commenters warn that the implementation plan may not be practical if the Commission is inundated with filings at the beginning of Stage Two.[508] Some commenters expressing concerns about transmission pricing policy believe that in the NOPR the Commission intended to establish the Stage One rate method as its own

[505] *E.g.*, ABATE, CO Com, DOE, Florida Power Corp, IBM, IL Com, MN DPS, Industrial Energy Applications, Missouri-Kansas Industrials, NIEP, ND Com, PG&E, PSNM, SBA, SC Public Service Authority, TDU Systems.

[506] *E.g.*, SC Public Service Authority.

[507] *E.g.*, Dayton, Carolina P&L, Citizens Utilities, Montana Power, Oglethorpe, OK Com, Seattle, Seminole EC, St. Joseph, Turlock, WA Com.

[508] *E.g.*, Christensen, Seminole EC.

official pricing policy, while other commenters argue that the Stage One rates demonstrate that broad pricing policy reform is needed as part of an open access rule.

Some commenters express concern about the timing of Stage One. Carolina P&L complains that the proposed implementation date is far too aggressive and proposes a one-year delay between the final rule and its implementation. Montana Power states that Stage One tariffs cannot be implemented in 60 days if any sort of functional unbundling is required. It insists that utilities should be given, at a minimum, 180 days in which to hire and train new employees and to install new equipment. Dayton P&L believes that Stage One tariffs should not be imposed until experience is gained with voluntarily-filed open access tariffs, but recommends further development of the tariffs for guidance purposes. It also requests that the Commission delay implementation of mandatory open access transmission until meaningful appellate review has taken place. Seattle suggests that the rate determination methods be phased in, so that the forced filing of transmission tariffs does not cause immediate and major shifts in cost allocation between old and new customers.

A few commenters express concern about the applicability of the implementation process. EEI and Consumers Power state that utilities that have already filed open access tariffs should have the option to use the two-stage implementation procedure so that they can obtain the terms and conditions of the NOPR tariffs without having to make a full-blown rate case filing.

Citizens Utilities asks that small distribution public utilities be exempt from Stage One if such entities can demonstrate that they do not use their own transmission systems to provide network service. Alternatively, it asks that application of Stage One to small public utilities be deferred until 60 days after they receive a section 211 request. Oglethorpe states that the proposed method of Stage One pricing is not appropriate for electric cooperatives that receive financing from the Rural Utilities Service (formerly the Rural Electrification Administration).

Commission Conclusion

In light of the many concerns raised regarding the proposed implementation process, the need to have adequate open access tariffs on file for all public utilities as soon as possible, the large number of utilities that have already filed some form of open access tariffs, and the desire to give public utilities flexibility to propose their own rates to be used in conjunction with the minimum non-rate terms and conditions necessary to ensure comparable service, we have decided to modify our proposed procedures. The details of the revised procedures are discussed below. In addition, special implementation requirements for coordination arrangements (power pools, public utility holding companies, and bilateral coordination arrangements) are discussed in Section IV.F.

The Revised Procedures

Implementation of the Rule will vary slightly for those public utilities that tendered for filing open access tariffs before the date of issuance of this Rule (including newly-tendered applications that have not been accepted for filing before the issuance of this rule) and those public utilities that did not tender open access tariffs before the issuance of this Rule. The former group is hereinafter referred to as Group 1 public utilities, while the latter group is referred to as Group 2 public utilities.

1. Group 1 Public Utilities

Group 1 public utilities will be required, within 60 days following publication of the Final Rule in the Federal Register, to make section 206 compliance filings that contain the non-rate terms and conditions set forth in the Final Rule pro forma tariff and identify any terms and conditions that reflect regional practices, as discussed below. Attached as Appendix E to this Rule is a list of Group 1 public utilities.

As to rates, we note that a transmission tariff rate is already in effect for all Group 1 public utilities, except for the few with recently-tendered applications that have not yet been accepted for filing. Most of these rates have been suspended, accepted for filing, set for hearing, and made subject to refund. Some have been accepted outright. Still others are the product of rate settlements.

We anticipate that our mandated changes in non-rate terms and conditions are compatible with the rate proposals already filed by Group 1 public utilities. Consequently, we are not going to divert the industry's resources by mandating any rate changes to fine-tune these interim tariffs. Should, however, a Group 1 public utility determine that certain rate changes are necessitated by the revised non-rate terms and conditions, it may file a new rate proposal under FPA section 205. Such filings must be ''conforming'' [509] under the Transmission Pricing Policy Statement and must be made no later than 60 days after publication of the Final Rule in the Federal Register. Intervenors may raise any concerns with the filings within 15 days after such filings.[510] We hereby impose a blanket suspension for any filings by Group 1 public utilities proposing rate changes necessitated by the new non-rate terms and conditions. These rates will go into effect, subject to refund, 60 days after publication of this Rule in the Federal Register (the same day on which the non-rate terms and conditions of the Final Rule pro forma tariff go into effect).[511]

If the Final Rule tariff's non-rate terms and conditions do not in the opinion of the utility necessitate a change in current rates, then the current rates will continue in effect under whatever refund conditions, if any, now apply to those rates.

2. Group 2 Public Utilities

Group 2 public utilities will be treated the same as Group 1 public utilities with regard to non-rate terms and conditions, but will be treated slightly differently from Group 1 as to rates, since Group 2 utilities have not filed any proposed rates. We will require these utilities to *either:* (i) Within 60 days following publication of the Final Rule in the Federal Register, make section 206 compliance filings that contain the non-rate terms and conditions set forth in the Final Rule pro forma tariff and identify any terms and conditions that reflect regional practices, as discussed below; and (ii) within 60 days following publication of the Final Rule in the Federal Register, make section 205 filings to propose rates for the services provided for in the tariff, including ancillary services; *or* (iii) make a ''good faith'' request for waiver. The rates must meet the standards for conforming proposals in the Commission's Transmission Pricing Policy Statement and comply with the guidance concerning ancillary services set forth in this order. Attached to this

[509] As described in the Transmission Pricing Policy Statement, a ''conforming'' proposal is one that meets the traditional revenue requirement and reflects comparability. FERC Stats. & Regs. ¶ 31,005 at 31,141.

[510] Given the brief comment period on the compliance filings, we will require public utilities to serve copies of their compliance filings (via overnight delivery) on: all participants in their current open access rate proceedings (if applicable); all customers that have taken wholesale transmission service from the utility after the date of issuance of the Open Access NOPR; and the state agencies that regulate public utilities in the states of those participants and customers.

[511] The Commission retains the right to reject such rates or to set them for hearing.

Rule as Appendix F is a list of Group 2 public utilities.

Intervenors may raise any concerns with these filings within 15 days after the filing.[512] We hereby impose a blanket suspension for all such rate filings; they will go into effect, subject to refund, 60 days after the publication of this Rule in the Federal Register (the same day on which the terms and conditions of the compliance tariffs go into effect).[513]

3. Clarification Regarding Terms and Conditions Reflecting Regional Practices

We have built a degree of flexibility into the tariffs to accommodate regional and other differences. Certain non-rate Final Rule pro forma tariff provisions specifically allow utilities either to follow the terms of the provision or to use alternatives that are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider (*e.g.*, time deadlines for scheduling changes, time deadlines for determining available capacity). In addition, other tariff provisions require utilities to follow Good Utility Practice. The definition of ''Good Utility Practice,'' contained in Section 1.14 of the Final Rule pro forma tariff, states that it ''is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region.'' Thus, where public utilities are permitted to follow regional practices, and elect to do so within 60 days of the date of publication of the Final Rule in the Federal Register, they should identify the regional practices in their compliance tariff filings.

4. Future Filings

We recognize that there may be circumstances in which a public utility believes that the Final Rule pro forma tariff does not provide sufficient flexibility or that the utility can propose superior non-rate terms and conditions. Thus, once the compliance tariff and conforming rates go into effect, which will be 60 days after publication of this Rule in the Federal Register, a public utility (either Group 1 or Group 2) may file pursuant to section 205 a tariff with terms and conditions that differ from those set forth in this Rule, provided that it: (1) Serves a copy of its filing on all wholesale customers for whom it has provided transmission service since March 29, 1995 (the date of the Open Access NOPR) and on the state agencies that regulate public utilities in the states where those customers are located; (2) identifies all deviations from its compliance tariff in its letter of transmittal; (3) provides, to the extent practical, a redlined version of the tariff; and (4) demonstrates that such terms and conditions are consistent with, or superior to, those in the compliance tariff. However, it may not seek to litigate fundamental terms and conditions set forth in the Final Rule.[514] In addition, the public utility may file whatever rates it believes are appropriate, consistent with the Transmission Pricing Policy Statement.

5. Waiver

Finally, as noted above, several commenters propose that public utilities that own few transmission facilities be granted waiver, or that application of the Rule to such utilities be deferred until 60 days after they receive a section 211 request. As discussed more fully in Section IV.K.2., we find that it is reasonable to permit certain public utilities for good cause shown to file, within 60 days after this Rule is published in the Federal Register, requests for waiver from some or all of the requirements of this Rule. The filing of a request in good faith for a waiver from the requirement to file an open access tariff will eliminate the requirement that such public utility make a compliance filing unless thereafter ordered by the Commission to do so. It will not, however, exempt such public utility from providing, upon request, transmission services consistent with the requirements of the Final Rule.

I. Federal and State Jurisdiction: Transmission/Local Distribution. In the original Stranded Cost NOPR, the Commission clarified that it has exclusive jurisdiction over unbundled retail transmission in interstate commerce by public utilities: it found that the Commission has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, up to the point of local distribution. In the Open Access NOPR, the Commission reaffirmed this jurisdictional determination[515] and also addressed the distinction between transmission and local distribution. The Commission stated three reasons for expressing its views on the distinction between Commission-jurisdictional transmission in interstate commerce and state-jurisdictional local distribution, in the context of unbundled retail wheeling by public utilities.[516] First, facilities that can be used for wholesale transmission in interstate commerce by a public utility would be subject to the Commission's open access requirements. Second, states have authority to address retail stranded costs and stranded benefits through their jurisdiction over facilities used in local distribution. Third, as the structure of the industry continues to change dramatically, utilities need to know which regulator has jurisdiction over which facilities and services in order to meet state and federal filing requirements. Accordingly, the NOPR set forth our jurisdictional analysis and several technical factors, for determining what constitutes ''facilities used in local distribution.''

For unbundled wholesale wheeling, the NOPR proposed to apply a functional test, *i.e.*, whether the entity to whom the power is delivered is a lawful reseller. For unbundled retail wheeling, the NOPR proposed to apply a combination functional-technical test that would take into account technical characteristics of the facilities used for the wheeling. The Commission proposed seven indicators of local distribution to be evaluated on a case-by-case basis:

[512] Group 2 public utilities must serve a copy of their filings (via overnight delivery) on all customers that have taken wholesale transmission service from them since March 29, 1995 (the date of issuance of the Open Access NOPR) and on the state agencies that regulate public utilities in the states where those customers are located.

[513] *But see* note 510, *supra*.

[514] As we stated in our ''Further Guidance Order,'' American Electric Power Service Corp., 71 FERC ¶ 61,393, 62,539–40, *order on rehearing*, 72 FERC ¶ 61,287, *order on rehearing*, 74 FERC ¶ 61,013 (1995), all tariffs need not be ''cookie-cutter'' copies of the Final Rule tariff. Thus, under our new procedure, ultimately a tariff may go beyond the minimum elements in the Final Rule pro forma tariff or may account for regional, local, or system-specific factors. The tariffs that go into effect 60 days after publication of this Rule in the Federal Register will be identical to the Final Rule pro forma tariff; however, public utilities then will be free to file under section 205 to revise the tariffs, and customers will be free to pursue changes under section 206.

[515] That determination included the situation in which a former bundled retail customer may need unbundled wheeling services from its previous public utility generation supplier, as well as unbundled wheeling from one or more intervening public utilities, in order to reach a distant generation supplier. In that scenario, the Commission would have jurisdiction over all of the transmission facilities used for the unbundled wheeling provided by the intervening public utilities. The NOPR also noted that the Commission would not have jurisdiction over the rates for the sale of generation by the distant supplier because the transaction would be a retail sale. FERC Stats. & Regs. ¶ 32,514 at 33,144.

[516] The term ''wheeling'' is intended to cover any delivery of electric energy from a supplier to a purchaser, i.e., transmission, distribution, and/or local distribution. The Commission also has jurisdiction to order wholesale transmission services in either interstate or intrastate commerce by transmitting utilities that are not also public utilities. See Tex-La Electric Cooperative of Texas, Inc., 67 FERC ¶ 61,019 (1994), reh'g pending.

(1) Local distribution facilities are normally in close proximity to retail customers.

(2) Local distribution facilities are primarily radial in character.

(3) Power flows into local distribution systems; it rarely, if ever, flows out.

(4) When power enters a local distribution system, it is not reconsigned or transported on to some other market.

(5) Power entering a local distribution system is consumed in a comparatively restricted geographical area.

(6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.

(7) Local distribution systems will be of reduced voltage.[517]

The NOPR concluded that the application of these tests will enable states to address stranded costs by imposing an exit fee on departing retail customers, or including an adder in the retail customers' local distribution rates.[518]

In the NOPR, the Commission also addressed buy-sell transactions in which an end user arranges for the purchase of generation from a third-party supplier and a public utility transmits that energy in interstate commerce and re-sells it as part of a ''nominal'' bundled retail sale to the end user. We explained that the retail sale is actually the functional equivalent of two unbundled sales (one transmission and the other the sale of power) and that we have exclusive jurisdiction over the voluntary sale by public utilities of unbundled transmission at retail in interstate commerce.[519]

Comments

Several commenters support the Commission's proposed jurisdictional demarcation.[520] San Diego G&E states that the Commission correctly proposed to look at both functional factors (such as whether the service is retail or wholesale) and technical factors (such as voltage). PG&E states that the NOPR's functional/technical test is preferable to a bright line voltage test.

Consumers Power states that the Commission has exclusive jurisdiction over all wheeling on an interconnected interstate transmission grid. It suggests that the Commission and the states act through a joint board or hearing to resolve jurisdictional differences and develop a bright line test.

PSE&G and PG&E express concern that if retail wheeling is implemented, there may be loopholes that would enable customers to evade state jurisdiction and thus avoid paying stranded costs. For example, PSE&G is concerned that a retail customer may request transmission service only and a state commission will be unable to attach a retail stranded cost surcharge to that customer. PG&E proposes adding another indicator to the functional/technical test—a final tap to a retail customer—to ensure that ''high-voltage'' retail customers do not evade the state's reach. Moreover, to ensure that retail customers cannot escape state jurisdiction, PG&E recommends that the Commission state, as a matter of policy, that ''*all* retail customers taking retail transmission service from their host utility *by definition* take service over local distribution facilities.''

CINergy agrees with the Commission that a distinction between transmission and local distribution is important, but emphasizes the practical need for clarity on a timely basis. To achieve certainty, CINergy proposes that the Commission allow public utilities to file, under section 205, classifications of their facilities as transmission or local distribution. CCEM endorses CINergy's proposal. Although NARUC disagrees that the Commission has jurisdiction over unbundled retail transmission, if the Commission reaffirms the NOPR regarding its jurisdiction, then NARUC supports CINergy's proposal.

PSE&G strongly supports the Commission's proposed case-by-case methodology for determining whether facilities should be classified as transmission or local distribution. SoCal Edison argues that since a utility may have difficulty determining which of its facilities are transmission and which are local distribution, utilities and states should be able to ask the Commission to classify a particular facility. Portland and Orange & Rockland suggest that the Commission provide a forum to resolve disputes over the correct classification of particular facilities.

Ohio Edison states that the Commission should assume jurisdiction over unbundled retail transmission, but only where a state has required this unbundling. It also believes that the Commission should assert jurisdiction over the ancillary services necessary to provide this jurisdictional service.

NYSEG argues that the Commission lacks jurisdiction over the transmission component of bundled retail service. On the other hand, NYSEG argues that the statute, legislative history, and case law reveal that the Commission has jurisdiction over unbundled retail wheeling from source to load, since it is transmission in interstate commerce. NYSEG argues that the ''local distribution'' exception to the Commission's jurisdiction applies only to bundled sales of power at retail.

Several state commissions assert that states have rate authority over all facilities used to provide retail service.[521] IL Com argues that states have rate authority over all facilities used to provide retail service, regardless of whether the NOPR would classify these facilities as transmission or local distribution.

MI Com, citing *Connecticut Light & Power Company* v. *Federal Power Commission,* 324 U.S. 515 (1945) (*CL&P*), and *Arkansas Electric Cooperative* v. *Arkansas Public Service Commission,* 461 U.S. 375, 393–94 (1983), contends that states have plenary jurisdiction over all aspects of retail service, including retail access and unbundled retail transmission service. It asserts that the Commission's effort to expand federal jurisdiction into transmission in connection with retail sales is without statutory justification.

Legal Environmental Assistance argues that the NOPR creates confusion about, and may intrude onto, state jurisdiction. NYMEX argues that when a state orders retail wheeling, the state should have jurisdiction over that transmission-only service.

Oklahoma G&E, citing *CL&P* and *United States* v. *California Public Utilities Commission,* 345 U.S. 295, 316 (1953), asserts that the Commission failed to explain that the term ''transmission in interstate commerce'' could have different meanings depending on the factual context in which the term is applied. It argues that ''transmission in interstate commerce'' means the movement, in bulk, of electric energy flowing in interstate commerce, as opposed to the movement of electric energy that has been subdivided for delivery to consumers.

Oklahoma G&E further argues that ''[t]he distinction between interconnected operation and radial operation corresponds precisely to this distinction between activities that have potential interstate effects and those that might have interstate effects but are a matter of primarily local concern.'' [522] Oklahoma G&E also disagrees that the transportation of electric energy sold at wholesale necessarily constitutes transmission in interstate commerce. It argues that the Commission has

[517] FERC Stats. & Regs. ¶32,514 at 33,145.

[518] *Id.* at 33, 144–45.

[519] As discussed *infra,* there also would be a component of local distribution in such a transaction that would be subject to state jurisdiction.

[520] *E.g.,* PG&E, Wisconsin Coalition, Com Ed.

[521] *E.g.,* NM Com, NC Com, AZ Com.

[522] Oklahoma G&E Initial Comments at 16.

misapplied case precedent and, by focusing on the level of the associated power sale, the Commission has misunderstood what constitutes a functional distinction between transmission in interstate commerce and local distribution.

NY Com asserts that the grant of jurisdiction to the Commission over wholesale power transactions in interstate commerce under section 201 of the FPA does not reduce the states' authority over local distribution (citing *CL&P* and *Federal Power Commission* v. *Florida Power & Light Company,* 404 U.S. 453, 467 (1972)). NY Com argues that the NOPR's assertion of exclusive jurisdiction over all facilities used to deliver electricity for resale, even those traditionally regarded as local distribution, violates Congress' assignment of local electric distribution to the states. It takes issue with the Commission's list of factors and says that states and the Commission should agree on a definition that preserves the traditional classification of local distribution facilities. According to NY Com, such definition should focus on the functional characteristics of local electric systems—*i.e.*, electricity flows into a comparatively restricted geographic area and does not flow back out of that area, and the power is consumed in that area.

NY IOUs argue that the Commission has jurisdiction over unbundled, but not bundled retail wheeling. It says that other factors, including the indicators listed in the NOPR, are irrelevant, and that even long-distance interstate transmission is under state jurisdiction as long as it is bundled with a retail sale. According to NY IOUs, this is the plain meaning of the FPA; resort to legislative history is unnecessary. NY IOUs bases this view on section 201(a), which says that federal regulation extends only to matters not subject to state regulation. NY IOUs says that the only matters subject to state regulation were bundled retail sales, and that since transmission was part of the bundle, Congress intended transmission to stay under state authority as long as it is part of that bundle. It also cites section 201(b), which sets forth exceptions from Commission jurisdiction, and section 201(c), which defines ''transmission in interstate commerce'' and thus also controls the definition of transmission in intrastate commerce. Finally, NY IOUs argues that the legislative history supports its view, as does the case law.

Central Louisiana believes that the costs of requiring a transmission provider to take unbundled transmission service for both wholesale and retail purposes would far exceed any benefits. In this regard, Central Louisiana says that states clearly have jurisdiction over bundled retail transmission charges and that the proposed approach could not be implemented without states giving up jurisdiction or the passage of new federal legislation.

MN DPS disagrees on legal and policy grounds with the Commission's assertion of jurisdiction over unbundled retail transmission services.[523] It maintains that the Commission's arguments do not negate the language of the FPA specifying that regulation of retail sales of electric energy is reserved to the states. MN DPS argues that the Commission's arguments in support of its position are not on point because the issue is state authority to set rates for retail sales, not interstate commerce. Further, it declares that jurisdiction over a service does not change simply because it is priced differently.

Several commenters argue that unbundled pricing should not expand the Commission's jurisdiction.[524] NARUC argues that the NOPR did not explain why the Commission's authority attaches only to unbundled retail transmission service, why unbundling is jurisdictionally significant, and how transmission of electricity to end users differs from unbundled interstate transmission of natural gas by local distribution companies, which is subject to state regulation. Thus, NARUC urges the Commission not to claim jurisdiction over unbundled retail transmission services.

NARUC also argues that the Commission's test for distinguishing between transmission and local distribution is not a bright line as discussed in *Federal Power Commission* v. *Southern California Edison Company,* 376 U.S. 205 (1964) (*Colton*). NARUC concludes that when a state determines to enable a retail customer to purchase power from a third-party provider, that state retains the authority to regulate the delivery service provided by the utility.

IL Com asserts that the test should be whether the utility function over which the Commission seeks to exercise jurisdiction is one which falls within the *Attleboro* gap.[525] It argues that the Commission has no legal authority to prescribe conditions under which a public utility may provide transmission service within its own service territory to its own retail customers. IL Com concedes that the court cases cited by the Commission can be interpreted to support widely disparate legal and policy positions, but argues that those cases resolved questions of Commission jurisdiction in circumstances where wholesale sales of electric power were being examined and not circumstances where retail sales are being considered. It contends that the question of whether the Commission should exercise jurisdiction over all transmission in retail wheeling has never been addressed before and requires a careful examination of the underlying purposes of Congress in enacting the FPA. IL Com explains that transmission by an Illinois utility of power to a retail consumer within its own service territory is not subject to Commission jurisdiction because that transmission was never within the *Attleboro* gap and has always been regulated by states.

OK Com recommends that the Commission apply to the electric industry the same policy that it has adopted concerning its regulation of the gas industry and leave unbundled retail service regulation to state authorities.

WI Com argues that if a utility offers unbundled retail access, jurisdiction over transmission services should continue to be based upon the historical demarcation between wholesale and retail transactions. KY Com argues that Congress did not intend, by authorizing wholesale wheeling in the Energy Policy Act, to change the longstanding division of jurisdiction between the Commission and the states. It claims that the NOPR ignores the limitation in the FPA that the Commission has no jurisdiction over retail sales service. NV Com cites several cases noting the states' historical authority to regulate retail rates.

IA Com proposes a definition of local distribution and transmission that would preserve the jurisdictional status quo and does not put a state commission in the position of losing authority over certain elements of a retail transaction should it allow retail wheeling. IA Com's proposed definition is as follows:

> Distribution—Service provided by a utility directly connected to an ultimate consumer of electricity is a distribution service with respect to electric energy delivered to that consumer.
>
> Transmission—Service provided by a utility with respect to electric energy to be delivered to an ultimate consumer through another utility is a transmission service.[526]

Montana Power states that a reasonable way to give effect to the ''local distribution'' exemption is to define ''local distribution'' as a bundled retail sale, even if interstate facilities are used.

[523] *See also* OH Com.

[524] *E.g.,* DOD, NM Com, KY Com, ABATE.

[525] *See* Public Utilities Commission v. Attleboro Steam & Electric Company, 273 U.S. 83 (1927).

[526] IA Com Initial Comments at 4.

Several commenters criticized the NOPR's functional/physical indicators. PA Com disagrees with the Commission's discussion of the FPA's legislative history and asserts that the FPA does not address the issue of what constitutes local distribution. PA Com contends that the issue was resolved by the Supreme Court in *CL&P* in a manner contrary to the Commission's technical-functional test and that the NOPR minimized *CL&P*. NM Com asserts that the proposed engineering and functional elements for determining the status of local distribution facilities fail to account for the governmental or legalistic test requirement of the FPA as identified in *CL&P*.

KY Com concludes that a physical definition of distribution facilities, based on objective criteria, is consistent with the FPA and is necessary to provide a clean line of demarcation.

CO Com argues that Congress used a transactional test rather than a functional test and that Congress intended all retail transactions to be under state jurisdiction. According to CO Com, there is concurrent jurisdiction over unbundled transmission in interstate commerce to an end-user. Moreover, CO Com asserts that unbundled intrastate transmission to a wholesale purchaser is under state jurisdiction (citing section 201(b)(1)). Finally, CO Com argues that the state has authority over unbundled transmission in intrastate commerce to an end-user when the transmission-providing utility, end-user, and generator are all within the same state.

Other commenters prefer a functional test. Natural Resources Defense, DOE, and Sustainable Energy Policy generally agree that a line needs to be drawn between transmission and local distribution but believe that the Commission's test is unnecessarily cumbersome or may lead to legal uncertainty, at least within the context of stranded benefits. Instead, Natural Resources Defense proposes the following functional test, which is based on end-use service:

> The Federal Power Act does not affect state regulators' jurisdiction to apply distribution charges—either volume-based or fixed—to electricity that is used by any utility customer to provide end-use services (as distinguished from electricity that is purchased for resale to end-use customers).[527]

Sustainable Energy Policy endorses Natural Resources Defense's position. DOE suggests that a functional definition of local distribution (*i.e.*, electricity provided for end-use service) may be the best way to avoid legal uncertainty.

EPA argues that the Commission's proposed physical definition may encourage gaming to avoid stranded costs and costs associated with public policy goals such as energy efficiency, renewable energy development and R&D funding, and a physical definition assumes that power flows into, and not out of, distribution systems, which would not allow for distributed generation (*e.g.*, fuel cells). Thus, EPA urges the Commission to adopt a functional definition that ''local distribution occurs whenever electricity is provided by a utility for end-use service.'' Alternatively, EPA suggests that the Commission add a provision to its approach that ''the provision of electricity for end-use service generally involves local distribution.'' Sustainable Energy Policy suggests a non-bypassable charge levied on all users of the distribution system. It endorses the policy formulation set forth by Natural Resources Defense in its initial comments. Reynolds wants to ensure that there is always at least concurrent state jurisdiction over lines used to serve end-use customers, since only states can order retail wheeling.

Detroit Edison argues that state/federal jurisdictional issues should be resolved by focusing on the use of the facilities. It says that facilities that are used to distribute a utility's own power to its own local customers should be subject to state regulation, while the use of facilities for wholesale power transactions or wholesale or retail transmission in interstate commerce should be under federal regulation.

Mountain States Petroleum Assoc argues that the Commission should use a functional test based on state boundaries: if a line is in more than one state, there is Commission jurisdiction; if a line is entirely within one state, there is state jurisdiction.

MD Com states that it believes that the Commission's proposed indicators for determining where to draw the line are adequate, but adds that it does not concede the Commission's assertion of jurisdiction over unbundled retail transmission.

Some commenters suggest that implementation of the NOPR's tests could have adverse consequences. NH Com objects to the NOPR's specific tests; for example, if the Commission asserts jurisdiction over facilities because they are not radial, New Hampshire's policy of encouraging looping rather than radial lines would have the ironic effect of destroying state jurisdiction. NJ BPU states that there may be situations when the NOPR factors would not produce the proper result. It requests that the final rule recognize the need for case-by-case flexibility in determining where federal jurisdiction ends, so that the Commission and the states can work cooperatively.

NRRI argues that the NOPR's test could make siting of new transmission lines more difficult because states have in the past required native load customers to pay that part of the transmission-related revenue requirement that is not covered by unbundled transmission service. NRRI contends that, if the Commission asserts jurisdiction over all unbundled transmission service and if there is a firm point-to-point service capacity right that has value and is reassignable, then state commissions might eliminate portions of the transmission systems subject to capacity rights from rate base. NRRI is also concerned that the NOPR's transmission/local distribution test could create a price squeeze between bundled and unbundled retail transmission rates.

IN Com argues that the NOPR's view of jurisdiction would discourage retail wheeling. It says that states will be reluctant to order wheeling if the result is that they lose jurisdiction over the previously rolled-in transmission aspect of the service. It suggests that the Commission use negotiated rulemaking to address jurisdictional issues.

Several commenters suggest alternative approaches to jurisdictional line-drawing. NV Com suggests that the Commission consider federal and state jurisdiction over transmission by using ''network'' and ''non-network'' concepts:

> The ''network'' concept for regulation recognizes that there is an interstate network of electric facilities used to link generation with loads. The operation of that network is indifferent to whether the electrical flows are retail or wholesale flows. Conceptually, events on the network could fall under federal jurisdiction. Where facilities provide essential service for the delivery of power, but do not substantially affect the electrical flows on the network, the facilities fall outside the network and would remain within the traditional domain of the state commission. As a consequence the delineation of federal and state jurisdiction evolves from the recognition of the events and where they occur as opposed to a rigid consideration of the physical properties of the facilities involved.[528]

NV Com further explains that the determination of what is a network event would require a case-by-case examination.

[527] Natural Resources Defense Initial Comments at 3.

[528] NV Com Reply Comments at 3.

OH Com asserts that Congress intends there to be a bright line between state and federal jurisdiction and that the Commission has failed to provide such a bright line. OH Com proposes the use of retail marketing areas to provide the bright line—the jurisdictional line would be at the point at which power enters the retail marketing area of the entity delivering the power to the retail customer. OH Com cites section 212(g) of the FPA, as amended by the Energy Policy Act, which provides that the Commission cannot issue any order under the FPA inconsistent with state law governing retail marketing areas.

Under OH Com's proposal, the Commission would have jurisdiction over the wheeling-out and wheeling-through components of retail wheeling and the state would have jurisdiction over the wheeling-in component due to its local nature. OH Com concludes that the Commission's approach ''fails to meet the legal standard FERC must consider, and is inconsistent with the 'savings clause' and legitimacy of 'retail marketing areas' as discussed in the amended FPA.'' [529] OH Com also explains that the Commission's approach ''is wreaking havoc on the state's ability to develop an interruptible buy-through arrangement to provide an increased competitive option for its retail customers.'' [530] OH Com further encourages the use of mutual deference to promote Congress' intent in mandating a system of federal/state cooperation. In support, OH Com cites federal and state enforcement of telecommunications laws. NRRI also suggests that the jurisdictional line be drawn at the retail marketing area.

DC Com argues that the NOPR test is too difficult to administer and will create problems in determining the rate base at the state level. It suggests that the Commission should have jurisdiction over transmission from the source to the boundary of the ''home'' utility that delivers the power to the customer, with state jurisdiction over all aspects of the transmission service within that utility's franchise territory. AZ Com also expresses doubts that the NOPR's test is workable.

Several commenters propose that the Commission and state authorities address the jurisdictional issue jointly. SBA characterizes the Commission's proposed demarcation line as ''laudable but misguided.'' [531] SBA recommends that a federal/state board be established to resolve the transmission/local distribution dilemma, similar to what Congress did for allocating costs between interstate and intrastate communications. SBA explains that the problem in the communications industry was the impossibility of allocating a portion of a single copper wire to interstate or intrastate service.

AZ Com notes that even if the Commission is correct, the FPA clearly does not preempt a state from concluding that retail transmission or other direct access programs should be implemented in that state. AZ Com suggests that there may be concurrent jurisdiction and that mutually agreed-upon principles should be implemented to determine which jurisdiction should be given deference.

MD Com states that in determining the status of particular facilities, the Commission should give substantial weight to determinations made by states. ABATE states that the Commission could initially defer to states with respect to the determination of rates, terms, and conditions, while maintaining the right to review and overturn the state determination.

If the Commission maintains its position concerning jurisdiction, NARUC argues that the Commission should not implement its multi-factor test, but should enter into discussions with state commissions to develop workable alternatives. NH Com argues that pricing the retail part of a transaction, even if it involves use of the transmission system, should be subject only to state jurisdiction. NH Com wants to create a mechanism by which state and federal regulators combine their efforts in cooperative regulation; it suggests several alternatives such as state/federal agreements for shared jurisdiction.

KY Com and NRRI object to the statement in the NOPR that retail buy-through service is really transmission service (subject to the Commission's jurisdiction) plus a sale of generation at retail (subject to state jurisdiction). From a policy standpoint, KY Com argues that the Commission's approach creates a powerful disincentive for a state to embark on changes that otherwise might foster a more competitive environment. NRRI argues that the Commission's approach may violate sections 212(g) and 212(h).

IL Com is concerned that industrial customers who get direct access may attempt to evade state jurisdiction, and thus avoid retail stranded cost charges, by bypassing facilities such as radial lines. It contends that retail wheeling rate surcharges would be a more effective means of recovering retail stranded costs if states were allowed to apply them to unbundled transmission and local distribution rates, not just the local distribution component of such rates.

NC Com asserts that ''[a] significant cottage industry may well arise solely to convert retail customers into wholesale customers, thereby subverting the intent of Congress as expressly set forth in EPACT.'' [532] If the Commission does not adopt NARUC's proposal, NARUC asserts that the Commission's functional test should not permit an end user to bypass the distribution service provided by the utility. It urges the Commission to assure that there will be some facility involved in the transaction that will be defined as providing a local distribution service.

NARUC also requests that the following sentence be added to proposed 18 CFR 35.27:

> Nothing in this part limits the authority of a State commission in accordance with State law (1) to allow or disallow the inclusion of the costs of electric energy purchased at wholesale in retail rates subject to such State commission's jurisdiction, (2) to establish competitive procedures for the acquisition of such electric energy, or (3) to establish non-discriminatory fees for the delivery of such electric energy to retail consumers for purposes established in accordance with State law.([533])

Duke is concerned about the potential for regulatory gaps, which could lead to costs not being recovered from either federal or state jurisdiction. Duke is also concerned that where facilities are used for both wholesale and retail transactions, costs might not be recovered if federal and state regulators use different methods of cost allocation.

In response to the NOPR's proposal for functional unbundling,[534] CA Com agrees that it is important to draw a distinction between transmission and local distribution and that a bright line is not possible, but suggests that corporate or functional unbundling

[529] Sections 212(g) and 212(h) of the FPA.

[530] We note that since OH Com filed its comments, it approved an interruptible buy-through plan. *See* Interruptible Electric Service Guidelines, Case No. 95–866–EL–UNC, __ PUR 4th __ (Ohio PUC Feb. 15, 1996). *See also* Central Illinois Light Company, Docket No. ER96–1075–000, 75 FERC ¶ _____ (1996) (accepting amendment to open access transmission tariffs that expands service eligibility to accommodate participation in experimental retail wheeling pilot program approved by the Illinois Commerce Commission); Illinois Power Company, Docket No. ER96–1285–000, 75 FERC ¶ _____ (1996); *cf.* Illinois Power Company, __ PUR4th __, No. 95–0494 (Illinois Commerce Commission Mar. 13, 1996) (offering retail direct access service providing transmission and ancillary services using the rates, terms, and conditions of Illinois Power's open access tariff on file with the Commission); recently introduced legislation in Rhode Island, H.B. 8124, the Utility Restructuring Act of 1996.

[531] SBA Initial Comments at 36.

[532] NC Com Initial Comments at 7.

[533] NARUC Reply Comments at 15–16.

[534] FERC Stats. & Regs. ¶ 32,514 at 33,080–83.

might provide a means to establish a workable bright line without relying on the more qualitative approach proposed in the NOPR. Arizona argues that rather than unbundling transmission for retail purposes, each utility should establish a distribution function that would obtain transmission on behalf of retail customers, taking service under the utility's tariff. Arizona states that this would simplify the allocation of transmission costs, since all transmission costs would be under the Commission's jurisdiction. Arizona argues that the Commission should permit the utility to recover the distribution rate approved by the state. According to Arizona, this would create a bright line between state and federal jurisdiction.

TX Com argues that the proposed test would not be applicable to intrastate utilities in Texas because they do not operate in interstate commerce. Thus, it asserts that it should continue to regulate Electric Reliability Council of Texas (ERCOT) transmission and distribution service and deal with stranded cost issues that arise in connection with any retail wheeling initiatives.

Several commenters object to the Commission's proposal to assert jurisdiction over transactions that are buy-sell transactions in name only.[535] AEP argues that the Commission should avoid an unnecessary conflict over state/federal jurisdiction that may be caused by the NOPR's statement that buy-sell transactions are in fact transmission subject to Commission jurisdiction. It suggests that the Commission attempt to reach agreement with the states on this matter or ask Congress for any necessary statutory change. Citizens Utilities also argues that the Commission should not unbundle the interstate transmission aspect of buy-sell transactions. It says that, unlike the analogous gas contracts, buy-sell arrangements on the electric side are not an end run around clear federal jurisdiction. Further, it argues that it would be very difficult to define those buy-sell transactions that truly belong under federal jurisdiction.

IL Com also objects to the NOPR's characterization of buy-sell transactions. It argues that the fact that a transaction becomes unbundled does not suddenly make part of it under federal jurisdiction. Nucor argues that there is no need for the Commission to resolve this issue now; it suggests that the buy-sell arrangement is only tangentially related to open access. It argues that each buy-sell transaction will have to be addressed individually.

UT Com seeks clarification as to what the Commission means by buy-sell arrangements:

> we currently authorize interruptible ''buy-through'' contracts, through which a retail customer, taking service subject to interruption for either economic or technical reasons, can opt to ''buy-through'' an interruption. The public utility purchases energy on behalf of the customer and sells it at cost to the customer. In our opinion, such transactions are not an example of a buy-sell transaction within the meaning of the proposed rule.[536]

DOD objects to the statement in the NOPR that ''buy-sell'' transactions are not really bundled retail service. It says that this view will discourage the development of innovative state programs, such as direct access programs. NYSEG also argues that buy-sell transactions are not under the Commission's jurisdiction. It argues that these transactions are unlike buy-sell transactions on the gas side, where the Commission asserted jurisdiction to prevent LDCs from circumventing the nondiscrimination standard it imposed on the release of capacity. NYSEG says:

> In contrast to its regulation of gas buy-sells, if the Commission regulates electric buy-sell transactions it would forego regulation of a transaction in which the Commission has a significant interest (*i.e.*, access to the upstream seller's transmission), to regulate a transaction in which the Commission has virtually no interest (*i.e.*, access to the distributing utility's system). Electric utilities must serve each retail customer irrespective of whether the customer takes traditional bundled service or retail buy-sell service. Unlike excess upstream gas pipeline capacity, the capacity on the local utility's electric system would not be allocated to another customer in a FERC jurisdictional transaction absent the electric buy-sell transaction. Electric buy-sell transactions are not designed so as to manipulate the assignment of upstream transmission capacity. Consequently, the impetus for FERC to reclassify gas buy-sell transactions as capacity assignments is not present in the electric context.[537]

NYSEG argues that there are only two possible grounds for the Commission's assertion of jurisdiction over electric buy-sell transactions: either (1) the sale for resale by the supplier is really a sale at retail to the end user, and the resale by the local utility is really unbundled retail wheeling; or (2) the Commission has jurisdiction over transmission service that is part of bundled retail service. It claims that the second ground is invalid because the transmission aspect of bundled retail service is distribution. It also claims that the first ground is invalid because it assumes that the sale by the supplier to the local utility is not a sale for resale even though the contract says that it is. NYSEG states:

> The logical outcome would be that FERC would *not* have jurisdiction over the sale by the supplier to the utility, including transmission by that supplier because it would be a bundled retail sale. This is because, if the commission holds the resale to be a retail wheel, then it would have to find that the sale by the supplier is a retail sale to the end user. The Commission cannot at once regulate the sale for resale and the ''retail transmission service.'' The Commission would regulate the transmission rates of the local franchise utility, although it would not regulate the access to such transmission service—a matter FERC leaves to state regulators. In the process, FERC would abandon the ability to regulate access to the supplier's bundled ''retail power sale and transmission service,'' a transaction that FERC arguably has an interest in regulating.[538]

Finally, NYSEG argues that if the Commission insists on asserting jurisdiction, it should at least grandfather existing contracts.

UT Industrials state that where there is a state barrier to a buy-sell transaction, the Commission should allow the utility to file a tariff with the Commission that would permit the utility to complete a voluntary buy-sell transaction as the NOPR proposes. However, it contends that when a state regulatory authority is authorized to, and has approved buy-sell transactions, it is not necessary for the Commission to become involved. It urges the Commission to allow such transactions to take place free of Commission regulation.

Commission Conclusion

In the discussion below, the Commission addresses the following jurisdictional issues raised in the prior NOPRs:

a. Does the Commission have jurisdiction over unbundled transmission in interstate commerce by a public utility when such transmission is used to transport electric energy that is sold to an end user?

b. If so, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to an end user?

c. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

[535] *See id.* at 33,082.

[536] UT Com Initial Comments at 4–5.

[537] NYSEG Initial Comments at 48 (footnote omitted).

[538] NYSEG Initial Comments at 50.

d. What procedures are appropriate for making jurisdictional determinations?

In addition, the Commission addresses concerns raised by state regulators which indicate that competition and open access are perceived as threatening the traditional regulatory functions of state commissions. The Federal Power Act differentiates between state and federal regulation of electric power. As we discuss below, the Commission believes that any change in state or federal jurisdiction over physical transmission assets and related costs will not affect the traditional tasks of state and federal regulators.

The wide range of jurisdictional interpretations and proposals in the comments reflects the fact that the legislative history of the FPA and case law interpreting federal/state jurisdiction under that Act and the Natural Gas Act grew out of a market structure in which electricity and transmission generally were bought and sold on a bundled basis. As a result, most transactions included either a retail or wholesale sale of electric energy and jurisdictional lines were drawn on the basis of this sale. Thus, the cases simply do not resolve dispositively these jurisdictional issues when they arise in the context of the market structures and unbundled transactions being contemplated in today's electric industry. However, after reviewing the extensive analysis of the FPA, legislative history, and case law contained in both our initial Stranded Cost NOPR and in our Open Access NOPR, and the comments received on that analysis, we continue to believe that we were correct in asserting jurisdiction over the transmission component of an unbundled interstate retail wheeling transaction. We therefore reaffirm our conclusion. We also reaffirm and clarify our determinations regarding the tests to be used to determine what constitute Commission-jurisdictional transmission facilities and what constitute state-jurisdictional local distribution facilities in situations involving unbundled wholesale wheeling and unbundled retail wheeling.[539]

At the same time, the Commission strongly supports the efforts of states to pursue pro-competitive policies. We recognize that jurisdictional issues raise overlapping Federal and state policy concerns that call for heightened cooperation among federal and state regulators. As discussed below, where states unbundle retail sales, we will give deference to their determinations as to which facilities are transmission and which are local distribution, provided that the states, in making such determinations, apply the seven criteria discussed in the NOPR and reaffirmed below. In addition, we clarify our view that there is an element of local distribution service in any unbundled retail transaction, and further clarify other aspects of our jurisdictional ruling to preserve state jurisdiction over matters that are of local concern and will remain subject to state jurisdiction if retail unbundling occurs.

We first address our legal determination that if unbundled retail transmission in interstate commerce occurs voluntarily by a public utility or as a result of a state retail access program, this Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission. No commenter has raised cases or legislative history not previously considered in our prior NOPRs, and we will not repeat here our full legal analysis of this issue.[540] However, we find compelling the fact that section 201 of the FPA, *on its face*, gives the Commission jurisdiction over transmission in interstate commerce (by public utilities) without qualification.[541] Unlike our jurisdiction over sales of electric energy, which section 201 of the FPA specifically limits to sales at wholesale, the statute does not limit our transmission jurisdiction over public utilities to wholesale transmission.

In response to those commenters (including NARUC) who argue that the Commission did not explain why its authority attaches only to unbundled, but not bundled, retail transmission in interstate commerce by public utilities, we believe that when transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail. Under the FPA, the Commission's jurisdiction over sales of electric energy extends only to wholesale sales. However, when a retail transaction is broken into two products that are sold separately (perhaps by two different suppliers: an electric energy supplier and a transmission supplier), we believe the jurisdictional lines change. In this situation, the state clearly retains jurisdiction over the sale of the power. However, the unbundled transmission service involves *only* the provision of ''transmission in interstate commerce'' which, under the FPA, is exclusively within the jurisdiction of the Commission. Therefore, when a bundled retail sale is unbundled and becomes separate transmission and power sales transactions, the resulting transmission transaction falls within the Federal sphere of regulation.

In asserting jurisdiction over unbundled retail transmission in interstate commerce by public utilities, the Commission in no way is asserting jurisdiction to order retail transmission directly to an ultimate consumer. Section 212(h) of the FPA clearly prohibits us from doing so. In addition, as stated in both the initial Stranded Cost NOPR and the Open Access NOPR, we do not address whether states have authority to order retail wheeling in interstate commerce. The Commission's assertion of jurisdiction is that *if* retail transmission in interstate commerce by a public utility occurs voluntarily or as a result of a state retail wheeling program, the Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission and public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205.

The Commission clarifies that nothing in this jurisdictional determination changes historical state franchise areas or interferes with state laws governing retail marketing areas of electric utilities. Section 212(g) of the FPA prohibits Commission orders that would be inconsistent with such laws. However, we reject arguments made by some of the commenters that section 212(g) could somehow be construed to give states authority over the rates, terms, and conditions of unbundled interstate transmission within retail marketing areas.[542] While our

[539] Not only do we conclude that our determinations are legally supportable under the case law, but we believe it is imperative to provide guidance to public utilities and state regulators as to our position on where the jurisdictional boundaries lie.

[540] The Commission's complete legal analysis on this issue, and on the related issue of what facilities are Commission-jurisdictional transmission facilities, and what are state jurisdictional local distribution facilities, are contained in Appendix G to this Rule.

[541] Section 201(b)(1) specifically exempts from Commission jurisdiction facilities used for transmission in intrastate commerce and transmission of electric energy consumed wholly by the transmitter. As a result, we have no jurisdiction over retail wheeling that occurs in Alaska, Hawaii and the Electric Reliability Council (ERCOT) portion of Texas since transactions in those areas are intrastate.

[542] The legislative history of FPA section 212(g) and its predecessor, former section 211(c)(3), indicates that the provision was focused on not interfering with state laws governing retail service territories and not permitting Commission wheeling orders ''for purposes of sale by a utility to an ultimate consumer who is within the service territory of another utility (other than the applicant) where such territory is established by or under State law, rule, or decision.'' *See* H.R. Conf. Rep. No. 1750, 95th Cong., 2d Sess. 92 (1978), *reprinted in*

Continued

jurisdiction cannot affect whether and to whom a retail electric service territory (marketing area) is to be granted by the state, and whether such grant is exclusive or non-exclusive, neither can state jurisdiction affect this Commission's exclusivejurisdiction over transmission in interstate commerce by public utilities.

In response to several of the commenters, we further clarify that the Commission's jurisdiction over the rates, terms, and conditions of unbundled retail transmission is no broader than our authority over transmission used for wholesale transactions, and will not affect matters otherwise left to the states by Congress.[543] The Federal Power Act recognizes that retail marketing areas are governed by state law. Moreover, we believe that states have authority over the *service* of delivering electric energy to end users. In exercising this authority, state regulatory commissions and state legislatures have traditionally developed social and environmental programs suited to the circumstances of their states. State regulation of most power production and virtually all distribution and consumption of electric energy is clearly distinguishable from this Commission's responsibility to ensure open and non-discriminatory interstate transmission service. Nothing adopted by the Commission today, including its interpretation of its authority over retail transmission or how the separate distribution and transmission functions and assets are discerned when retail service is unbundled, is inconsistent with traditional state regulatory authority in this area.

The Commission reiterates its strong interest in preventing any balkanization of the interstate power market. Although the Commission believes its Final Rule will accommodate retail competition, if it is offered voluntarily by a utility or ordered by a state, our policies relate only to the bulk power market and not traditional state regulation of the retail market.[544]

NARUC has requested that the Commission specifically clarify in § 35.27 of its proposed rules[545] that nothing in our final rule limits the authority of a state commission ''to allow or disallow the inclusion of the costs of electric energy purchased at wholesale in retail rates subject to such State commission jurisdiction.'' We will adopt NARUC's proposal with modification, but add it as a separate subsection. The Final Rule adopts a new § 35.27(b) as follows:

Nothing in this part (i) shall be construed as preempting or affecting any jurisdiction a state commission or other state authority may have under applicable state and federal law, or (ii) limits the authority of a state commission in accordance with state and federal law to establish (a) competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or (b) non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with state law.

With respect to the Commission's adoption of the Open Access NOPR's functional/technical tests for determining what facilities are Commission-jurisdictional facilities used for transmission in interstate commerce and what facilities are state-jurisdictional local distribution facilities, the case law supports a bright line for unbundled wholesale transmission, *i.e.*, transmission of electric energy that is being sold for resale. This is consistent with the bright line drawn by Congress to fill the *Attleboro* gap for regulating wholesale sales of electric energy. The case law also supports a bright line with respect to retail transmission by intervening utilities, *i.e.*, transmission by those utilities between the new retail generation supplier and the public utility that previously provided bundled retail service to the end user. However, despite many commenters' arguments to the contrary, we cannot divine such a bright line for unbundled retail transmission by the public utility that previously provided bundled retail service to the end user. In fact, the limited case law, including *CL&P* and *Colton*, supports a case-by-case determination.[546] Accordingly, we believe our technical test, with its seven indicators, will permit reasoned factual determinations in individual cases.

Although we are unable to draw the bright line for local distribution facilities that many commenters would like, we believe it is important to make two clarifications regarding local distribution in the context of retail wheeling. First, even when our technical test for local distribution facilities identifies no local distribution facilities for a specific transaction, we believe that states have authority over the *service* of delivering electric energy to end users. Second, through their jurisdiction over retail delivery services, states have authority not only to assess stranded costs but also to assess charges for stranded benefits, such as low-income assistance and demand-side management. Because their authority is over services, not just the facilities, states can assign stranded costs and benefits based on usage (kWh), demand (kW), or any combination or method they find appropriate. They do not have to assign them to specific facilities.[547]

Thus, while we believe in most cases there will be identifiable local distribution facilities subject to state jurisdiction, we also believe that even where there are no identifiable local distribution facilities, states nevertheless have jurisdiction in all circumstances over the service of delivering energy to end users. Under this interpretation of state/federal jurisdiction, customers have no incentive to structure a purchase so as to avoid using identifiable local distribution facilities in order to bypass state jurisdiction and thus avoid being assessed charges for stranded costs and benefits.

Based on concerns raised by state commissions as well as some utilities, we have further determined that it is appropriate to provide deference to state commission recommendations regarding certain transmission/local distribution matters that arise when retail wheeling occurs. We also believe it is important to develop mechanisms to avoid regulatory conflict and to help provide certainty to utilities as to which regulator has jurisdiction over which facilities. These are discussed below.

1978 *U.S. Code Cong. & Ad. News* 7797, 7826. Nothing on the face of section 212(g) or the legislative history of either the Energy Policy Act or PURPA indicates that the provision in any way affects the Commission's authority over rates, terms, and conditions of transmission in interstate commerce by public utilities.

[543] Among other things, Congress left to the States authority to regulate generation and transmission siting. *See* FPA sections 201(b) and 211(d)(1); section 731 of the Energy Policy Act.

[544] This Final Rule will not affect or encroach upon state authority in such traditional areas as the authority over local service issues, including reliability of local service; administration of integrated resource planning and utility buy-side and demand-side decisions, including DSM; authority over utility generation and resource portfolios; and authority to impose non-bypassable distribution or retail stranded cost charges.

[545] Section 35.27 of the proposed rules provided that any public utility seeking authorization to engage in sales for resale at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity first placed in service on or after 30 days from the date of publication of the Final Rule in the Federal Register. FERC Stats. & Regs. ¶ 32,514 at 33,154.

[546] As noted, the Commission's detailed legal analysis is contained in Appendix G. We are particularly persuaded by the Supreme Court's statement that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. *See* CL&P, 515 U.S. at 534–35.

[547] As noted above, states retain authority over state integrated resource planning, utility resource portfolios, and utility buy-side and demand-side decisions.

Determining where to draw the jurisdictional line for facilities used in unbundled retail wheeling transactions will involve case-specific determinations that evaluate the seven local distribution indicators that we are adopting. We believe that the Commission should take advantage of state regulatory authorities' knowledge and expertise concerning the facilities of the utilities that they regulate. Therefore, in instances of unbundled retail wheeling that occurs as a result of a state retail access program, we will defer to recommendations by state regulatory authorities concerning where to draw the jurisdictional line under the Commission's technical test for local distribution facilities, and how to allocate costs for such facilities to be included in rates, provided that such recommendations are consistent with the essential elements of the Final Rule.[548] Moreover, we recognize that in some cases the Commission's seven technical factors may not be fully dispositive and that states may find other technical factors that may be relevant. We will consider jurisdictional recommendations by states that take into account other technical factors that the state believes are appropriate in light of historical uses of particular facilities.

Some commenters have asked the Commission to provide a forum to prevent or resolve disputes over the correct classification of facilities as transmission or local distribution. As a means of facilitating jurisdictional line-drawing, we will entertain proposals by public utilities, filed under section 205 of the FPA, containing classifications and/or cost allocations for transmission and local distribution facilities. However, as a prerequisite to filing transmission/local distribution facility classifications and/or cost allocations with the Commission, utilities must consult with their state regulatory authorities. If the utility's classifications and/or cost allocations are supported by the state regulatory authorities and are consistent with the principles established in the Final Rule, the Commission will defer to such classifications and/or cost allocations.[549] We encourage public utilities and their state regulatory authorities to attempt to agree to utility-specific classifications and allocations that the utility may file at the Commission.

A number of commenters have asked the Commission to defer to state commission recommendations or decisions regarding rates, terms and conditions of unbundled retail transmission in interstate commerce by public utilities. Some have suggested that we set broad guidelines for such rates, terms, and conditions, and then allow states to actually implement the guidelines. While the Commission cannot simply turn over its jurisdiction for the states to implement, we understand the concerns raised by many state regulators and believe that deference to state commissions with regard to rates, terms, and conditions may be appropriate in some circumstances, as discussed below.

As we determined in the NOPR, when unbundled retail wheeling in interstate commerce occurs, the transaction has two components for jurisdictional purposes—a transmission component and a local distribution component. The Commission has jurisdiction over facilities used for the transmission component of the transaction, and the state has jurisdiction over facilities used for the local distribution component.[550] Thus, the rates, terms and conditions of unbundled retail transmission by a public utility must be filed at the Commission. When this occurs, we will generally expect unbundled retail wheeling customers to take service under the same FERC tariff that applies to wholesale customers. However, if the unbundled retail wheeling occurs as part of a state retail access program, it may be appropriate to have a separate retail transmission tariff[551] to accommodate the design and special needs of such programs. In such situations, the Commission will defer to state requests for variations from the FERC wholesale tariff to meet these local concerns, so long as the separate retail tariff is consistent with the Commission's open access policies and comparability principles reflected in the tariff prescribed by this Final Rule. In addition, rates must be consistent with our Transmission Pricing Policy Statement, and the guidance herein concerning ancillary services.[552]

A final jurisdictional issue raised in the Open Access NOPR concerns buy-sell transactions. We remain concerned, just as we were with buy-sell arrangements in the gas industry, that buy-sell arrangements can be used by parties to obfuscate the true transactions taking place and thereby allow parties to circumvent Commission regulation of transmission in interstate commerce. Thus, we reaffirm our conclusion that we have jurisdiction over the interstate transmission component of transactions in which an end user arranges for the purchase of generation from a third-party. However, we recognize that there is a wide range of programs and transactions that might or might not fall within this category. We will address these on a case-by-case basis.

In summary, the Commission reaffirms and clarifies its prior jurisdictional conclusions and tests for determining the demarcation between federal and state jurisdiction over transmission in interstate commerce and local distribution. We have attempted to address these issues in a way that provides for flexibility and recognition of legitimate state concerns. With regard to retail services, we recognize the states' concerns that the unbundling of retail transactions would result in changes from what historically has been regulated by the states (principally, the rates of transmission assets previously included in retail rate base). However, the decision to provide unbundled retail wheeling is not the Commission's to make because we have no authority to order transmission directly to an ultimate consumer. In addition, even if a retail access program occurs, we do not believe the unbundling of retail transactions will radically change fundamental state authorities, including authority to regulate the vast majority of generation asset costs, the siting and maintenance of generation facilities and transmission lines, and decisions regarding retail service territories. Further, the Commission intends to be respectful of state objectives so long as they do not balkanize interstate transmission of power or conflict with our interstate open access policies. As the electric industry and state regulatory authorities continue to develop new competitive market structures and consider retail wheeling programs, we believe that the tests and mechanisms we have provided in this Rule will accommodate both Federal and state interests and will help provide jurisdictional certainty to market participants.

[548] In order to give such deference, we expect state regulators to specifically evaluate the seven indicators and any other relevant facts and to make recommendations consistent with the essential elements of the Rule.

[549] This should also alleviate some concerns about the potential for costs not being accounted for if the Commission and a state commission use different methods of allocating costs.

[550] As discussed above, even if there were instances where no local distribution *facilities* are used, we believe states have authority over the *service* of delivering electric energy to end users.

[551] *I.e.*, the tariff would be different from the tariff that applies to wholesale customers. Such tariff would still be filed with the Commission under FPA section 205.

[552] In applying the principles of the Final Rule to retail transmission tariffs, the Commission clearly cannot order retail wheeling directly to an ultimate consumer. *See* FPA section 212(h).

J. Stranded Costs

1. Justification for Allowing Recovery of Stranded Costs

In the Supplemental Stranded Cost NOPR, the Commission noted that the Open Access Rule would give a utility's historical wholesale customers greatly enhanced opportunities to reach new suppliers.[553] This would affect the way in which utilities have recovered costs under the traditional regulatory system that, on the one hand, imposed an obligation to serve,[554] and, on the other hand, permitted recovery of all prudently incurred costs. We noted that if customers leave their utilities' generation systems without paying a share of these costs, the costs will become stranded unless they can be recovered from other customers. The Commission stated in the NOPR that we must address the costs of the transition to a competitive industry by allowing utilities to recover their legitimate, prudent and verifiable stranded costs simultaneously with any final rule we adopt requiring open access transmission.[555]

Comments

Virtually all of the investor-owned utility commenters as well as commenters representing state commissions and other constituencies support the NOPR's premise that stranded costs can be created when a customer switches suppliers. They endorse the proposal to allow the recovery of legitimate and verifiable stranded costs.[556] Numerous commenters also support the Commission's proposal to link stranded cost recovery with open access tariffs. These commenters agree that the recovery of stranded costs is critical to the successful transition of the industry to an open transmission access, competitive industry.[557] Commenters such as EEI and NU submit that open access and stranded cost recovery should be implemented simultaneously; that unbundled transmission service should not be required until a stranded cost recovery mechanism is in place. Some commenters propose that if the full recovery of stranded costs is disallowed as a result of rehearing or judicial review, utilities that have filed open access transmission tariffs should be permitted to withdraw them, or the Commission should otherwise reconsider its rule on open access transmission in light of such a reversal.[558]

Commenters representing the financial community reiterate their strong support for the full recovery of stranded costs, noting that the prospect of not recovering stranded costs could erode a utility's ability to attract capital which, in turn, could impede the long-term goal of achieving competitive wholesale markets.[559] Several commenters also argue that stranded cost recovery is economically efficient and is necessary to ensure parity among competitors and to avoid uneconomic bypass.[560]

The commenters that oppose allowing utilities to recover legitimate and verifiable stranded costs repeat many of the arguments that were raised in response to the initial Stranded Cost NOPR. For example, a number of commenters argue that the risk that a utility could lose customers (and thereby incur stranded costs) is not a new phenomenon created by regulatory and statutory initiatives that utilities could not have anticipated.[561] Some commenters argue that there was never an implied obligation to serve at wholesale.[562] According to TDU Systems, monopoly power, not regulatory obligation, has kept wholesale customers captive over the years.

Other commenters argue that allowing the recovery of stranded costs would make it uneconomic for customers to seek alternative sources of power and that the prospect of liability for and protracted litigation over stranded cost claims would create paralyzing uncertainty for customers, uncertainty that may dissuade them from taking advantage of new opportunities in the wholesale power market.[563] Some commenters also argue that stranded cost recovery would be a disincentive to efficient operation by affording the greatest protection to utilities that made the worst investment decisions.[564]

Commenters also argue that the scope of the proposed rule is overbroad; that stranded cost recovery should be allowed, if at all, on a case-by-case basis; that there should be no presumption that every utility will experience stranded costs; and that utilities should not be allowed to recover 100 percent of prudently incurred stranded costs.[565]

Several commenters suggest that there is no factual basis for the stranded cost rule, citing a lack of evidence of a wholesale stranded cost problem.[566] TDU Systems refers to a Resource Data International study that shows that, of $114 billion in potential investor-owned utility stranded investment, only $10.4 billion is associated with wholesale transactions.[567] Others submit that the

[553] FERC Stats. & Regs. ¶ 32,514 at 33,095.

[554] The Supplemental Stranded Cost NOPR described such an obligation as explicit at retail and arguably implicit at wholesale. FERC Stats. & Regs. ¶ 32,514 at 33,101.

[555] *Id.* at 33,095–96, 33,101.

[556] *See, e.g.,* EEI, Atlantic City, Arizona, Carolina P&L, Centerior, Central Hudson, Detroit Edison, Duke, Duquesne, Entergy, Florida Power Corp, El Paso, Houston, NIPSCO, NU, Oklahoma G&E, Otter Tail, PG&E, Puget, Southern, San Diego G&E, SCE&G, SoCal Edison, Montana, Montana-Dakota Utilities, NSP, Utilities For Improved Transition, NC Com, PA Com, Electric Consumers Alliance, American National Power, NE Public Power District, MEAG, OH Coops, Seattle, NY Energy Buyers, SBA, TVA, Utility Workers Union, Big Rivers EC, Central EC, Citizens Lehman, NGSA, AGA, Montaup, NIEP.

[557] *See, e.g.,* EEI, Coalition for Economic Competition, EGA, CINergy, Electric Consumers Alliance, Atlantic City, Com Ed, Consumers Power, Dayton P&L, Dominion, Duke, El Paso, NEPCO, NIMO, NIPSCO, Ohio Edison, Florida Power Corp, PECO, Pennsylvania P&L, PSNM, Public Service Co of CO, Southern, SCE&G, VEPCO, Texas Utilities, DOE, CA Energy Com, CO Com, PA Com, NE Public Power District, SMUD, Brazos, Sunflower, PJM, Utility Workers Union, Utility Investors Analysts, Nuclear Energy Institute, SoCal Gas, AGA, Utility Shareholders, LPPC. Although DOD agrees that addressing stranded costs is a critical part of the transition to a more competitive industry, it submits that there is nothing in the Open Access NOPR that should affect the treatment of stranded costs because the Open Access NOPR would not change the contracts that govern existing wholesale transactions. It argues that the Commission will have ample opportunity to decide these matters before the present wholesale long-term contracts expire.

[558] *E.g.,* Utilities For Improved Transition, PECO, Utility Workers Union, Dayton P&L.

[559] Utility Investors Analysts, Utility Shareholders.

[560] *See, e.g.,* EEI, SCE&G, Montana, Com Ed.

[561] *E.g.,* TAPS, IN Industrials, Air Liquide, Texas Industrials, Detroit Edison Customers, AMP-Ohio.

[562] *E.g.,* TDU Systems, Competitive Enterprise.

[563] *See, e.g.,* Missouri Joint Commission, Omaha PPD, American Forest & Paper, TAPS, AMP-Ohio, Kansas Commission, VA Com, Nucor, Torco, IPALCO, DE Muni, Municipal Energy Agency Nebraska, Air Liquide, Arkansas Cities, Detroit Edison Customers, Cleveland, Texas-New Mexico, Blue Ridge, Suffolk County, NM Industrials, PA Munis, Caparo, ABATE, NRRI, Building Owners, Alma, WEPCO, Total Petroleum. SC Public Service Authority asserts that the Commission has not adequately addressed the anticompetitive potential of exit fees and the potential shifting of losses from high-cost to low-cost producers. It says that the Commission should renotice any further proposal that it develops to permit a reasoned analysis of anticompetitive concerns.

[564] *E.g.,* TAPS, AMP-Ohio, IPALCO, Suffolk County, Competitive Enterprise, NY Energy Buyers, Supervised Housing, Central Illinois Light, WP&L, SC Public Service Authority, KS Com.

[565] *E.g.,* Alma, IPALCO, Suffolk County, CO Consumers Counsel, Arkansas Cities, Central Illinois Light, NY AG, NASUCA, VA Com, NY Energy Buyers, UT Industrials, NM Industrials, NJ Ratepayer Advocate, WEPCO, IN Industrials, ABATE, AZ Com.

[566] *E.g.,* ELCON, TDU Systems, Texas-New Mexico, Central Illinois Light.

[567] However, Utilities for Improved Transition refers to a report by Moody's Investor Service estimating that the stranded costs of the Nation's 114 largest electric utilities under open access transmission will be $135 billion in the next ten years (13 to 14 times greater than the costs stranded by the introduction of open access transportation of

Commission should obtain more current data concerning the magnitude of potential stranded cost recovery before issuing the final rule.[568] In reference to the statement in the Supplemental NOPR that the Commission will continue to gather information on the magnitude of potential stranded costs,[569] DE Muni states that the Commission must commit to making public all the data it obtains so that all can evaluate the impact of the recovery of stranded costs on an ongoing basis.

NRRI submits that the Commission has drawn the wrong conclusion from its natural gas industry experience. According to NRRI, pipelines were ''caught in an unusual transition'' by changes caused by Congress and the Commission. In the case of the electric industry, NRRI submits that although there are uneconomic wholesale power contracts, the Commission is not responsible for this situation.[570]

Several commenters suggest that the Commission condition a utility's ability to recover stranded costs upon the utility agreeing to take certain actions (such as reducing environmental effects [571] or ensuring the payment of costs that are stranded if the utility commences direct service to an end-use customer that was previously a wholesale customer of a transmission dependent utility [572]), or agreeing to refrain from certain actions (such as seeking unilaterally to terminate or modify IPP contracts).[573] CCEM proposes that open access, conversion rights, and divestiture should each be a precondition to a utility's eligibility for any stranded cost recovery. VT DPS submits that, if the Commission adopts a stranded cost rule, it should limit utility stranded cost claims to those cases where the utility can demonstrate that its costs have been rendered unrecoverable as a direct result of the final rule.[574]

A number of commenters object that the proposed rule contains no provisions for non-transmission-owning utilities to collect stranded costs.[575] Illinois Municipal Electric Agency asks the Commission to consider providing a forum for municipals to recover stranded costs from their customers under the same guidelines as investor-owned utilities. Recognizing that the FPA gives the Commission no general jurisdiction over municipalities for purposes of rate regulation,[576] Illinois Municipal Electric Agency argues that the FPA nevertheless does not prevent the Commission from providing a forum for municipalities that may experience stranded costs as a result of new federal regulations. NE Public Power District, RUS, and rural electric cooperative commenters object that the NOPR gives public utilities a greater chance than other transmitting utilities to recover stranded costs from departing customers by offering public utilities two avenues of recovery (an exit fee under a power sales contract or a transmission surcharge) but offering other transmitting utilities only one avenue (a transmission surcharge).[577]

PA Munis objects that the Commission's proposal to impose stranded costs only on wholesale requirements customers (and not on other wholesale customers) is unduly discriminatory and counter to the goals of the Open Access NOPR. It submits that the Commission's proposal, by subjecting a wholesale requirements customer to increased transmission rates for stranded costs not levied on other wholesale customers, is indistinguishable in substance from the pre-Order 436 plan held to be discriminatory in *Maryland People's Counsel* v. *FERC*.[578]

ELCON and others [579] urge the Commission to clarify that stranded costs do not arise when a customer leaves a system because its plant becomes uneconomic or the customer wishes to co-generate or self-generate. They note that ''[t]hese alternatives have always existed and do not arise from new opportunities for wholesale and retail wheeling.'' [580]

Commission Conclusion

We reaffirm our preliminary determination that the recovery of legitimate, prudent and verifiable stranded costs should be allowed. Having considered the arguments raised by the commenters that oppose stranded cost recovery, we continue to believe that utilities that entered into contracts to make wholesale requirements sales under an entirely different regulatory regime should have an opportunity to recover stranded costs that occur as a result of customers leaving the utilities' generation systems through Commission-jurisdictional open access tariffs or FPA section 211 orders,[581] in order to reach other power suppliers. As we indicated in the Supplemental Stranded Cost NOPR, we do not believe that utilities that made large capital expenditures or long-term contractual commitments to buy power years ago should now be held responsible for failing to foresee the actions this Commission would take to alter the use of their transmission systems in response to the fundamental changes that are taking place in the industry.[582] We will not ignore the effects of recent significant statutory and regulatory changes on the past investment decisions of utilities.[583] While, as some commenters point out, there has always been some risk that a utility would lose a particular customer, in the past that risk was smaller. It was not unreasonable for the utility to plan to continue serving the needs of its wholesale requirements customers and retail customers, and for those customers to expect the utility to plan to meet future customer needs. With the new open access, the risk of losing a

natural gas). It notes that this estimate covers costs stranded by transmission in interstate commerce of both wholesale and retail power, and submits that both types of costs are relevant to this proceeding because of the Commission's jurisdiction over the transmission rates for wheeling to both wholesale and retail customers.

[568] *E.g.*, Central Illinois Light, Utility Workers Union, Alcoa.

[569] *See* FERC Stats. & Regs. ¶ 32,514 at 33,105.

[570] According to NRRI, the Commission did not ''berate'' electric utility management to sign uneconomic contracts in the manner that NRRI contends the Commission and Congress ''berated'' pipeline management. NRRI Initial Comments at 6. NRRI also objects that the proposed rule is a departure from what occurred in other deregulated industries (where no stranded cost recovery was allowed) and that the Commission should provide a fuller explanation as to why it believes allowing utilities full recovery of legitimate and verifiable stranded costs is the correct course of action.

[571] *E.g.*, Legal Environmental Assistance, Conservation Law Foundation.

[572] *E.g.*, TDU Systems.

[573] *E.g.*, EGA, LG&E. EGA and LG&E further argue that if a utility is able to abrogate a QF contract, a QF should be entitled to recover its costs based upon the same equities of reliance upon governmental approvals, changed regulatory regimes, and reasonable expectation.

[574] VT DPS argues that under Order No. 636, the Commission allowed recovery of costs that would be rendered ''unrecoverable'' because the costs would not be incurred to provide transportation service and because there would be no wholesale load from which to recover the costs. It suggests that when a utility loses wholesale load or a municipality establishes a new distribution system, the utility's costs are not necessarily rendered unrecoverable.

[575] *E.g.*, PA Munis, Missouri Joint Commission, TAPS, Municipal Energy Agency Nebraska.

[576] *But see* FPA section 212(a), 16 U.S.C. 824k(a).

[577] RUS objects that, at the same time, an RUS-financed cooperative that is a transmitting utility would be required to provide reciprocal open access to its public utility supplier, which is also its customer and its competitor.

[578] 761 F.2d 768 (D.C. Cir. 1985).

[579] *E.g.*, VA Com, DE Muni, LG&E, Mountain States Petroleum Assoc.

[580] ELCON July 25, 1995 Comments at 6.

[581] Hereafter referred to collectively as the ''new open access'' or ''open access transmission.''

[582] FERC Stats. & Regs. ¶ 32,514 at 33,101–02.

[583] Contrary to NRRI's claim, and as explained in the NOPR (*see, e.g.*, FERC Stats. & Regs. ¶ 32,514 at 33,063–68), the electric industry's transition to a more competitive market *is* driven in large part by statutory and regulatory changes beyond the utilities' control.

customer is radically increased. If a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, we believe that the utility is entitled to recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer.[584]

We learned from our experience with natural gas that, as both a legal and a policy matter, we cannot ignore these costs. During the 1980s and early 1990s, the Commission undertook a series of actions that contributed to the impetus for restructuring of the gas pipeline industry. The introduction of competitive forces in the natural gas supply market as a result of the Natural Gas Policy Act of 1978[585] and the subsequent restructuring of the natural gas industry left many pipelines holding uneconomic take-or-pay contracts with gas producers. When the Commission initially declined to take direct action to alleviate that burden, the U.S. Court of Appeals for the District of Columbia Circuit faulted the Commission for failing to do so.[586] The court noted that pipelines were ''caught in an unusual transition'' as a result of regulatory changes beyond their control.[587]

As we stated in the Supplemental NOPR, the court's reasoning in the gas context applies to the current move to a competitive bulk power industry. Indeed, because the Commission failed to deal with the take-or-pay situation in the gas context, the court invalidated the Commission's first open access rule for gas pipelines. Once again, we are faced with an industry transition in which there is the possibility that certain utilities will be left with large unrecoverable costs or that those costs will be unfairly shifted to other (remaining) customers. That is why we must directly and timely address the costs of the transition by allowing utilities to seek recovery of legitimate, prudent and verifiable stranded costs. At the same time, however, this Rule will not insulate a utility from the normal risks of competition, such as self-generation, cogeneration, or industrial plant closure, that do not arise from the new availability of non-discriminatory open access transmission. Any such costs would not constitute stranded costs for purposes of this Rule.

We are issuing the Stranded Cost Final Rule simultaneously with the Open Access Final Rule because we believe that the recovery of legitimate, prudent and verifiable stranded costs is critical to the successful transition of the electric industry to a competitive, open access environment. We believe that our decision today will be upheld by the courts. While the D.C. Circuit is still considering the various appeals of Order No. 636,[588] it has already upheld, in at least two instances, our ultimate decision to allow the recovery of costs stranded in the transition to a competitive natural gas industry.[589] As a result, we reject the suggestions of some commenters that a utility's obligation to comply with the provisions of the Open Access Final Rule should be conditioned upon final court approval of the Stranded Cost Final Rule. We also decline otherwise to condition a utility's ability to recover its stranded costs. As described in greater detail in Section IV.J.8, if a utility can make the necessary evidentiary showings, it will be eligible for stranded cost recovery.

With regard to the magnitude of potential wholesale stranded costs, as the Supplemental Stranded Cost NOPR recognizes, the level may be small relative to that of retail stranded costs. Nevertheless, wholesale costs may be stranded as a result of open access transmission. Because the significance of such costs to the utilities that would face them may be great (and the prospect of not recovering such costs could erode utilities' ability to attract capital and be very detrimental to a diverse array of utility shareholders), we believe that we have a responsibility to allow for the recovery of such costs.

We disagree with the commenters who contend that this Rule would discriminate against certain segments of the industry, such as non-transmission-owning utilities (who would not be allowed to collect stranded costs) or wholesale requirements customers (who would be subject to stranded cost charges while other wholesale customers would not). These commenters misconstrue the purpose of this Rule and the nature of the stranded costs for which this Rule would allow recovery. This rule is designed to address a new and specific problem: The fact that a utility that historically has supplied bundled generation and transmission services to a wholesale requirements customer and incurred costs to meet reasonably expected customer demand may experience stranded costs when its customer is able to reach a new generation supplier due to the availability of open access transmission. This rule proposes a solution to that problem by allowing the recovery of legitimate, prudent and verifiable costs incurred by a utility to provide service to a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of the utility. The opportunity for extra-contractual wholesale stranded cost recovery is allowed for only a discrete set of requirements contracts for which the utility can demonstrate that it had a reasonable expectation of continuing service, as well as for retail-turned-wholesale situations in which the utility satisfies the necessary evidentiary criteria. Thus, the fundamental premise of this rule—namely, that a utility should have an opportunity to recover reasonably-incurred costs that arise because open access use of the utility's transmission system enables a generation customer to shop for power—would not apply to a non-transmission-owning utility that, by definition, has no transmission by which its generation customer can escape to another supplier.

The same historical relationship discussed above, including the expectation of continued service, justifies imposing the stranded costs covered by this rule on wholesale requirements customers only (not on non-requirements customers that contract separately for transmission services to deliver their purchased power). Requirements customers historically were long-term customers who typically did not expect to take service from other suppliers. Utilities thus assumed they would continue

[584] As a result, the opportunity for wholesale stranded cost recovery under this Rule is limited to utilities that provided sales of generation and transmission under wholesale requirements contracts, and to utilities that provided service to retail customers that convert to wholesale customer status, and that face the potential inability to recover costs when their customers are able to reach new suppliers through open access transmission.

[585] 15 U.S.C. 3301 *et seq.*

[586] *AGD*, 824 F.2d at 1021.

[587] *Id.* at 1027.

[588] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, 57 FR 13267 (April 16, 1992), FERC Stats. & Regs. ¶ 30,939 (1992), *order on reh'g*, Order No. 636–A, 57 FR 36128 (August 12, 1992), FERC Stats. & Regs. ¶ 30,950 (1992); *order on reh'g*, Order No. 636–B, 57 FR 57911 (December 8, 1992), 61 FERC ¶ 61,272 (1993), *reh'g denied*, 62 FERC ¶ 61,007 (1993), *appeal pending* United Distribution Companies, *et al.*, v. FERC, No. 92–1485, *et al.*, (D.C. Cir. Oral Argument Held Feb. 21, 1996).

[589] *See, e.g.*, Public Utilities Commission of the State of California v. FERC, 988 F.2d 154, 166 (D.C. Cir. 1993) (''FERC, with the backing of this court, has been at pains to permit pipelines to recover these (take-or-pay) costs, which have accumulated less through mismanagement or miscalculation by the pipelines than through an otherwise beneficial transition to competitive gas markets.''); Western Resources, Inc. v. FERC, 72 F.3d 147 (D.C. Cir. 1995).

serving these customers and may have made significant investments based on that long-term expectation. In contrast, utilities did not (and do not today) generally make investments for short-term economy-type transactions. Rather, such transactions were entered into only when the utility temporarily had available capacity or energy that could be provided to the buyer at a price lower than the buyer's decremental cost. The utility was not obligated in any way—either explicitly or implicitly—to provide for the needs of non-requirements customers. Because coordination transactions were not the cause of stranded investment decisions, it would be inappropriate to allocate such costs to non-requirements customers.

Further, although some commenters object that the Rule would give public utilities a greater opportunity than other transmitting utilities to recover stranded costs, our jurisdiction over transmitting utilities that are not also public utilities is limited. If the selling utility under an existing contract is a transmitting utility that is not also a public utility, its wholesale requirements contracts are not subject to this Commission's jurisdiction. Thus, we can allow such a transmitting utility to recover stranded costs only through Commission-jurisdictional transmission rates under sections 211 and 212 of the FPA. Nevertheless, in the context of a specific section 211 case, we would expect to apply similar principles to the extent possible to assure full stranded cost recovery. We also encourage such transmitting utilities to negotiate mutually agreeable stranded cost provisions with their customers.

2. *Cajun Electric Power Cooperative, Inc.* v. *FERC*[590]

In the Supplemental Stranded Cost NOPR, the Commission made a preliminary finding that the *Cajun* court decision does not bar the recovery of stranded costs as proposed in the NOPR and set forth our reasoning in support of that finding.[591]

Comments

Various commenters contend that the proposal to permit recovery of stranded costs at all, or particularly through transmission rates of departing customers, fails to address the *Cajun* court's concerns.[592] These commenters repeat many of the same arguments previously raised in this proceeding, which we have already addressed. Some commenters argue that including generation-based stranded costs in transmission rates is an anticompetitive tying arrangement and that *Cajun* compels the Commission to abandon this aspect of its stranded cost proposal or, at a minimum, to explain how the chosen method of recovery differs from that remanded in *Cajun*.[593]

Several commenters[594] question whether the NOPR's stranded cost provisions would undermine the ''meaningful'' access to alternative suppliers referenced by the *Cajun* court.[595] For example, Arkansas Cities asserts that the Commission has failed to address whether a transmitting utility retains market power over transmission even after imposition of an open access tariff. It contends that this question is vital to determining whether imposition of stranded costs would interfere with a wholesale transmission customer's meaningful access to other power suppliers.

Some commenters also submit that the proposed procedures for a customer to obtain an estimate of its stranded cost liability are inadequate because they do not ameliorate the uncertainty confronting the customer, which was a concern of the court in *Cajun*. They suggest that a customer would still face the prospect of litigation concerning whether a proposed stranded cost charge is appropriate.[596]

Other commenters argue that *Cajun* requires a trial-type evidentiary hearing before stranded costs may be recovered. They question whether the Commission's generic proposals on open access and the Commission's statements about the need to recover stranded costs are adequate.[597] ELCON references the *Cajun* court's statement that ''if the Commission is wrong at the outset concerning the *possibility* of legitimate stranded investment cost, it is not fair or reasonable to create such a mechanism for recovery.''[598] ELCON submits that the factual record does not demonstrate any significant wholesale stranded cost problem and, as a result, a final rule allowing recovery of such costs would not be ''fair or reasonable.''

Many other commenters, in contrast, believe that the NOPR is distinguishable from the case that was before the court in *Cajun* and that the Commission has fully addressed the *Cajun* court's concerns. According to the Coalition for Economic Competition, this proceeding is very different from the *Cajun* proceeding because the proposed rule would not automatically permit utilities to charge market-based rates. The Coalition for Economic Competition states that in the absence of generic market-based rate authorization, there is no basis in *Cajun* for barring the recovery of stranded investment in transmission tariffs.[599]

A number of commenters agree with the Commission that the *Cajun* court was concerned with the need for a more complete explanation of the basis for stranded cost recovery and the mechanism selected for such recovery. These commenters believe that the NOPR provides both the evidentiary record for addressing these concerns on a generic basis and the opportunity for all participants to present evidence and arguments.[600]

Noting the *Cajun* court's concern as to whether the wholesale customer in that case had ''meaningful'' access to alternative suppliers, a number of commenters agree that the Commission, through the open access provisions of the NOPR, is in fact providing wholesale customers meaningful, reasonable access to alternative suppliers.[601]

As evidence that the *Cajun* court was concerned with inadequate explanation and procedures and did not find that stranded costs could never be justified, several commenters point out that the *Cajun* court did not mention the D.C. Circuit's landmark decision in *AGD*, which strongly supports stranded cost

[590] 28 F.3d 173 (D.C. Cir. 1994) (*Cajun*).

[591] FERC Stats. & Regs. ¶ 32,514 at 33,105–06.

[592] *E.g.*, APPA, ABATE, ELCON, Central Illinois Light, IL Com, VT DPS.

[593] *See, e.g.*, ELCON, American Forest & Paper, MMWEC, Cajun, IL Com, PA Com, VT DPS, Education, DE Muni, IN Industrials, Texas-New Mexico, Las Cruces, Blue Ridge, Suffolk County, Total Petroleum, NM Industrials, PA Munis.

[594] *E.g.*, Arkansas Cities, PA Munis, NM Industrials.

[595] *See Cajun*, 28 F.3d at 179.

[596] *See, e.g.*, Suffolk County, Arkansas Cities, Education.

[597] *E.g.*, PA Com, NY Com, RUS.

[598] *Cajun*, 28 F.3d at 179 (emphasis in original).

[599] SC Public Service Authority notes this distinction as well (Initial Comments at 78): ''In *Cajun*, the court was not criticizing the recovery of stranded assets as an abstract matter, but specifically as an integral part of a set of tariffs designed to justify market-based rates on the basis that the open access tariff adequately mitigated market power despite the provision permitting recovery of stranded assets.'' It suggests that if the Commission decides to allow utilities to recover stranded costs from departing customers, any utility recovering such costs should not be allowed to charge market-based rates.

[600] *See, e.g.*, EEI, NEPCO, Centerior, Electric Consumers Alliance, Southern.

[601] *E.g.*, Omaha PPD, Com Ed, Florida Power Corp. Com Ed also submits that the argument by the petitioners in *Cajun* that ''there really is no such thing as stranded investment, only a failure to compete'' ignored the circumstances under which the investments were made. It states that electric utilities did not incur the costs of generation facilities (and long-term fuel and power supply contracts) because they were less efficient competitors, but to satisfy their obligation in a fully-regulated market to provide service to all who request it.

recovery.[602] For example, Coalition for Economic Competition suggests that construing *Cajun* to hold that stranded cost recovery is always anticompetitive would be at odds with *AGD* and other decisions that have upheld the Commission's policy of allowing recovery of the costs of the transition to competitive markets.[603]

Numerous commenters also support the Commission's conclusion that stranded cost recovery through transmission rates is not a tying arrangement.[604] Among other things, these commenters argue that a tying claim requires that the defendant force the sale of a separate product with the sale of a product over which it has market power, and that here there is no second product being tied to transmission. Several commenters also suggest that, in any event, stranded cost recovery as proposed in the NOPR would be considered a legitimate business justification under the antitrust laws.[605] Com Ed explains that the Commission, as part of its effort to enhance competition in generation by opening up the transmission network, is avoiding placing on utilities the entire burden of the stranded costs resulting from their past regulatory obligations; it is not permitting utilities to maintain a monopoly of power sales.

Commission Conclusion

We reaffirm that we do not interpret the *Cajun* court decision as barring the recovery of stranded costs. The court in that case did not bar stranded cost recovery, as some commenters suggest; it instead found that the Commission had not provided adequate proceedings and had not fully explained its decision. The Commission had failed to hold an evidentiary hearing concerning whether the inclusion of a stranded cost recovery provision in a particular utility's transmission tariff, along with other provisions in the tariff, resulted in the adequate mitigation of Entergy's market power so as to justify market-based rates. The court also found that the Commission had failed to explain adequately its approval of the stranded cost provision, among other provisions. In contrast, as discussed below, we have addressed in this consolidated proceeding (the Stranded Cost NOPR, the Supplemental Stranded Cost NOPR, the Open Access NOPR, and the Open Access/Stranded Cost Final Rule) all of the *Cajun* court's concerns.

Our interpretation of *Cajun* is bolstered by a recent opinion of the Court of Appeals for the D.C. Circuit (the same circuit that decided *Cajun*) that confirms the validity of Commission imposed stranded cost recovery mechanisms in the transition to competitive markets. In *Western Resources, Inc.* v. *FERC*,[606] the court affirmed the Commission's decision to allow the recovery of costs stranded in the transition of the natural gas industry to a competitive market.[607] We believe that, by this decision, the court has again affirmed the Commission's ability to allow stranded cost recovery, as long as we follow adequate procedures and explain our decision.[608]

We are providing in this proceeding the evidentiary record to support our decision to allow the recovery of legitimate, prudent and verifiable stranded costs on a generic basis. We also are ensuring the ''meaningful'' access to alternative suppliers that was identified as a concern of the *Cajun* court. The Open Access Final Rule is designed to attack one essential element of market power—namely, control over transmission access. The standard we are adopting for transmission service is far stricter than the standard we used at the time *Cajun* was decided; we now require non-discriminatory open access transmission, as well as a code of conduct and non-discriminatory sharing of transmission information (OASIS). The collective effect of these actions is that public utilities that own, control or operate interstate transmission facilities will not be able to favor their own generation and will have to compete on an equal basis with other suppliers.[609] All public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce will have tariffs on file that offer to any eligible customer any transmission services that the public utility could provide to itself, and under comparable terms and conditions.

We note that the *Cajun* court identified several provisions in Entergy's proposed tariff as potentially restraining competition: Entergy's retention of sole discretion to determine the amount of transmission capability available for its competitors' use;[610] the point-to-point service limitation;[611] the failure to impose reasonable time limits on Entergy's response to requests for transmission service;[612] and Entergy's reservation of the right to cancel service in certain instances,[613] even where a customer had paid for transmission system modifications.[614] These types of provisions, which have the potential to restrain competition, will not be allowed under the Open Access Rule. On the contrary, the Final Rule pro forma tariff contains terms and conditions to ensure the provision of non-discriminatory transmission service. In addition, the requirements that a public utility take service under its own tariff, adopt a non-discriminatory transmission information network, and separate power marketing and transmission functions further ensure non-discrimination and remove constraints to fair competition. Thus, the nondiscriminatory open access

[602] *See, e.g.*, Com Ed, Coalition for Economic Competition, NYSEG, Entergy.

[603] *See, e.g.*, K N Energy, Inc., 968 F.2d 1295 at 1301 (D.C. Cir. 1992), Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 874 (D.C. Cir. 1993).

[604] *E.g.*, EEI, Com Ed, Consumers Power, SoCal Edison, Salt River, Entergy.

[605] *See* State of Illinois ex rel. Burris v. Panhandle Eastern Pipe Line Co., 935 F.2d 1469, 1483 (7th Cir. 1991), *cert. denied*, 502 U.S. 1094 (1992) (pipeline's refusal to transport gas that an LDC customer purchased from another supplier was ''genuinely and reasonably motivated by the need to limit its potential take-or-pay liability, not by a desire to maintain its monopoly position by excluding competition in the sale of natural gas''); City of Chanute v. Williams Natural Gas Company, 743 F. Supp. 1437 (D. Kan.), *aff'd*, 955 F.2d 641 (7th Cir. 1990) (pipeline's refusal to transport third-party gas was motivated by legitimate business concerns, including desire to prevent take-or-pay liability, not by an anticompetitive motive).

[606] 72 F.3d 147 (D.C. Cir. 1995).

[607] *Id.* at 152.

[608] As we noted in the Supplemental NOPR, the same court had earlier instructed the Commission in the *AGD* case that the Commission *must* consider the transition costs borne by regulated utilities when the Commission changes the regulatory rules of the game. FERC Stats. & Regs. ¶ 32,514 at 33,106.

[609] *Id.* at 33,065–67.

[610] In contrast to the tariff under review in *Cajun*, the Final Rule pro forma tariff provides that available transmission capability (ATC) must be calculated and posted on the transmission provider's Open Access Same-time Information System (OASIS) pursuant to new Part 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEM AND STANDARDS OF CONDUCT FOR PUBLIC UTILITIES of the Commission's regulations. Section 37.6 provides in pertinent part that along with posting its ATC on its OASIS node, a public utility must make all data used in the calculation publicly available, on request. Section 37.4 provides that employees of the public utility and any affiliate that are engaged in merchant functions are prohibited from having preferential access to any transmission-related information. Additionally, the regulations provide auditing and monitoring procedures to safeguard against discriminatory practices.

[611] In contrast to the tariff under review in *Cajun*, the Final Rule pro forma tariff requires the provision of point-to-point and network service.

[612] In contrast to the tariff under review in *Cajun*, the Final Rule pro forma tariff requires reasonable time limits for responses to transmission requests. Specifically, Section 17.5 provides that a transmission provider must respond to a request for firm service as soon as practicable, but not later than thirty days after the date of receipt of a completed application.

[613] In contrast to the tariff under review in *Cajun*, the Final Rule pro forma tariff does not allow firm transmission service to be cancelled after the service has been commenced. However, Section 7.3 of the Final Rule pro forma tariff does provide that in the event of a customer default, the transmission provider may, in accordance with Commission policy, file and initiate a proceeding with the Commission to terminate service.

[614] *Cajun*, 28 F.3d at 179–80.

transmission that is the hallmark of this Rule is designed to ensure meaningful access to alternative suppliers and goes far beyond that which was offered in the transmission tariff that was under review in *Cajun*.

We also have addressed the *Cajun* court's concern over the *method* of recovery. In that case, Entergy proposed to include a charge in the departing customer's transmission rate to recover its stranded investment costs. The court said that this might constitute an anticompetitive tying arrangement.[615] As we explained in the Supplemental NOPR, the stranded cost recovery procedure we prescribe in this Rule is a *transitional mechanism only* that is intended to enable utilities to recover costs prudently incurred under a different regulatory regime. The purpose and effect of the stranded cost recovery mechanism that we approve in this Rule is to facilitate the transition to competitive wholesale power markets. Although we recognized in the Supplemental NOPR that stranded cost recovery may delay some of the benefits of competitive bulk power markets for some customers, such transition costs must nevertheless be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets. The stranded cost recovery mechanism that we direct here is a necessary step to achieve pro-competitive results. In the long term, the Commission's rule will result in more competitive prices and lower rates for consumers.

The Commission's approach also is consistent with the traditional regulatory concept of cost causation. We do not believe it is an illegal tying arrangement to hold a customer accountable for the consequences of leaving an incumbent supplier if, under our rules, the incumbent supplier must show a reasonable expectation of continuing service before it can recover stranded costs from the customer.

Further, in response to the *Cajun* court's concern that the Commission had failed in that case to explain adequately its approval of the stranded cost provision and other provisions, we have provided in this proceeding a detailed explanation of the fundamental industry and regulatory changes that have given rise to the potential for stranded costs; the transitional nature of stranded costs; the critical need to deal with these costs in order to reach more competitive wholesale markets; and the consumer benefits that will result from competitive generation markets. We also have provided a detailed explanation of the terms and conditions in the Final Rule pro forma tariff that will meet the non-discriminatory open access service requirement.

Several commenters (and the *Cajun* court) express concern for the need to provide as much certainty as possible for departing customers concerning their potential stranded cost obligation. Without some certainty, customers may be unable to shop for alternative suppliers. In response to these concerns, we have modified the stranded cost recovery mechanism to include a formula for calculating a departing customer's potential stranded cost obligation. As discussed in greater detail in Section IV.J.9, the revenues lost formula is designed to provide certainty for departing customers and to create incentives for the parties to address stranded cost claims between themselves without resort to litigation.

We conclude that we have fully explained our decision to allow the recovery of legitimate, prudent and verifiable costs that are stranded in the transition to competitive wholesale bulk power markets. We also have provided ample opportunity for all concerned to present arguments and evidence on the issue. Further, we have significantly strengthened our open access requirements to ensure mitigation of transmission market power. Thus, we have fully addressed the concerns of the *Cajun* court.

3. Responsibility for Wholesale Stranded Costs (Whether To Adopt Direct Assignment to Departing Customers)

In the Supplemental Stranded Cost NOPR, the Commission made a preliminary finding that direct assignment of stranded costs to the departing wholesale generation customer is the appropriate method for recovery of such costs.[616]

Comments

Numerous parties representing all constituencies support direct assignment of stranded costs to the departing generation customer.[617] These commenters argue, among other things, that direct assignment is consistent with the cost causation principle and preferable to increasing the delivered price of electricity to a whole region through the imposition of a wires charge, and that recovery of stranded costs from remaining customers would not be in the public interest. Several state commenters seek assurance from the Commission that native load customers will be held harmless from stranded costs resulting from other customers leaving the system.[618] KY Com submits that the possible results of a broader assessment of stranded costs, with the related uncertainty of its impact on the utilities' cost of capital, is more problematic in the long run than the possibility that the direct assignment of stranded costs would deter customers from shopping for power.

Although TAPS opposes stranded cost recovery in general, it submits that, if the Commission decides to allow recovery, the Commission should directly assign stranded costs and not spread them across the board to all transmission users.

Several commenters also oppose any allocation of stranded cost liability to shareholders.[619]

Some commenters state that direct assignment of stranded costs sends the correct pricing signals during the transition to a competitive regime. For example, Electric Consumers Alliance states that a wholesale customer should be able to obtain power elsewhere, but that the motive to do so should not be to escape responsibility for sunk investments made on its behalf. El Paso submits that failure to make the departing generation customer liable for stranded cost recovery would create a ''first-off'' incentive; the customers that leave the system first would not suffer from higher future rates designed to recover prudently incurred costs from the reduced base of remaining customers.

Some commenters support direct assignment but oppose recovery of stranded costs through transmission rates. These commenters prefer an exit fee or lump-sum approach that would reflect cost causation in an unbundled fashion.[620] DOJ maintains that a

[615] Notably, the court stated: ''This is, in essence, a tying arrangement, (citation omitted), and *it might be fine if the purpose of the arrangement were not to cabin Entergy's market power.*'' *Id.* at 177–78 (emphasis added).

[616] FERC Stats. & Regs. ¶32,514 at 33,108.

[617] *See, e.g.*, EEI, Atlantic City, Arizona, Carolina P&L, Centerior, Com Ed, Duke, HP&L, Duquesne, Florida Power Corp, Omaha PPD, Alcoa, AEC & SMEPA, BG&E, Central Electric, Detroit Edison, El Paso, Montana-Dakota Utilities, Ohio Edison, PECO, PSNM, Southern, Sierra, SoCal Edison, Tucson Power, Utilities For Improved Transition, Cajun, NRECA, EGA, Electric Consumers Alliance, FL Com, PA Com, Knoxville, Salt River, KY Com, ND Com, California DWR, LA DWP, TVA, Utility Investors Analysts, Texas Utilities, LG&E, Utility Shareholders.

[618] *E.g.*, NC Com, UT Com, NJ Ratepayer Advocate.

[619] *E.g.*, SCE&G, Com Ed, Ky Com, NC Com. SCE&G states that the Commission misinterpreted its previous comments by suggesting in the Supplemental NOPR that SCE&G believed shareholders should bear part of the costs.

[620] *E.g.*, Texas Utilities, DOJ.

transmission adder is analogous to an excise tax and that the excise tax approach would distort pricing signals and customers' decisions on the use of electric power. It submits that the lump-sum approach, on the other hand, would establish a fixed, sunk liability that would not depend upon how much transmission service the departing customer takes in the future.[621]

Other commenters oppose direct assignment as being inconsistent with wholesale competition.[622] They argue that placing all of the responsibility for stranded costs on departing generation customers would discourage customers from switching to other generation providers and would thereby inhibit competition.[623] Some commenters also assert that departing generation customers are not the sole ''cause'' of stranded costs.[624] VT DPS contends that direct assignment cannot be reconciled with the Commission's refusal to allow the imposition of exit fees by gas pipelines when their wholesale customers depart.[625]

Some commenters support spreading the burden of stranded costs broadly among departing customers, shareholders, and remaining wholesale customers on the basis that it would be equitable for all industry stakeholders to share both the benefits and the costs of the transition to competition.[626]

Others support spreading the costs to all customers through, for example, a meter charge to all utilities (to be passed on to customers), a one-time charge across the total market base, an access fee on the transmission system, or a component of transmission rates.[627] Nordhaus proposes a uniform national tax on all customers, at a rate that declines over time in a predetermined manner. He submits that this approach would remove ''gaming'' between utilities and potential exiters, would ensure that the stranded costs are not disproportionately loaded on price-sensitive demanders (that is, exiting customers), and would gradually disappear over time in a predictable fashion, thereby increasing the predictability of the new market.

PA Munis disputes the Commission's assertion in the Supplemental Stranded Cost NOPR that there is no compelling reason to assess costs broadly. It argues that a broad-based recovery mechanism that distributes uneconomic stranded costs to all power users would minimize the competition-inhibiting aspects of the Commission's proposed surcharge on departing generation customers. In a similar fashion, NSP states that across-the-board recovery from all users of the grid would recognize the societal benefits to be achieved from the transition to a competitive bulk power market and would reflect precedent set during the move to competition in the natural gas and telephone industries. It submits that the cost per service unit would be lower than exit fees assigned to particular customers and would eliminate the need for detailing stranded cost exposure for each customer contemplating leaving the system.

FTC submits that some investments that now appear as stranded costs may have been intended to benefit customers over a wider area than a single utility. It suggests that national regional assessment methods could recover stranded costs undertaken to benefit these wider groups of customers.

We also received comments suggesting that less than full recovery of stranded costs should be allowed. A number of commenters urge the Commission to require some shareholder liability for stranded cost recovery to give utilities an incentive to mitigate.[628] Several of these commenters assert that utility shareholders should be required to pay a portion of any stranded costs (such as 25–50 percent) because at least some of the responsibility for stranded costs lies with poor business decisions by utility management.[629] Occidental Chemical proposes that the Commission grant utilities a ''presumption of prudence'' in return for requiring them to absorb a minimum of 25 percent (up to 50 percent) of stranded costs, citing as support the Commission's precedent in the natural gas industry.

Commission Conclusion

We reaffirm our decision that direct assignment of stranded costs to the departing wholesale generation customer through either an exit fee[630] or a surcharge on transmission is the appropriate method for recovery of such costs. We believe it is appropriate that the departing generation customer, and not the remaining generation or transmission customers (or shareholders), bear its fair share of the legitimate and prudent obligations that the utility undertook on that customer's behalf.

In reaching this decision, we have carefully weighed the arguments supporting direct assignment of stranded costs against those supporting a more broad-based approach, such as spreading stranded costs to all transmission users of a utility's system.

[621] In its reply comments, Utility Working Group disputes DOJ's arguments that a transmission adder is analogous to an excise tax and would distort competition. It argues that DOJ's claim of price distortion ignores the fact that the costs that would be associated with a transmission adder consist of a portion of the previous wholesale power price—the markup above the utility's marginal cost that had regulatory approval. Utility Working Group says that because the utility's price and its competitor's price will contain this same charge for the utility's sunk and regulatory costs (the difference between the utility's regulated rate and its incremental cost), they will compete on the basis of their respective incremental costs. It also suggests that transmission adders can be designed on a lump-sum basis so that they are not tied to the amount of electricity purchased.

[622] *E.g.*, ELCON, NYMEX, IL Industrials, Missouri-Kansas Industrials, Philip Morris, Fertilizer Institute, Coalition on Federal-State Issues.

[623] Some commenters also oppose the Commission's proposal to allow the recovery of generation-related costs through transmission rates as being in contravention of cost-causation principles (*e.g.*, VT DPS) or in violation of section 212(a) of the FPA, which they contend limits cost recovery to transmission-related costs (*e.g.*, IL Industrials, Las Cruces).

[624] *E.g.*, ELCON, IL Industrials, NY Energy Buyers, TX Industrials, Missouri-Kansas Industrials, Caparo, IBM, PA Munis, Education. For example, Caparo submits that business decisions by incumbent utilities are the cause of stranded costs.

[625] In support of this proposition, the VT DPS cites Transwestern Pipeline Co., 44 FERC ¶61,164 at 61,536 (1988); El Paso Natural Gas Co., 47 FERC ¶61,108 at 61,314 (1989); El Paso Natural Gas Co., 72 FERC ¶61,083 (1995). It also contends that the Commission recently treated a notice provision in an El Paso contract as a conclusive, rather than a rebuttable, presumption. VT DPS cites other differences between the Commission's treatment of the natural gas and the electric utility industries. It notes that the Commission has not proposed to allow existing wholesale electric customers to get out of their contracts early, as it did in the gas area.

[626] *E.g.*, ELCON, IN Industrials, Reynolds, Philip Morris, ABATE, Missouri-Kansas Industrials, Aluminum.

[627] *See, e.g.*, American National Power, NIEP, NSP, SBA, Coalition on Federal-State Issues, Pennsylvania P&L, Consolidated Natural Gas, Nordhaus, PA Munis. Consumers Power states that it does not oppose direct assignment, but asks that the final rule not preclude utilities from proposing alternative recovery mechanisms, including those that assess stranded costs on all transmission customers as part of the transmission rate. It suggests that utilities should not be precluded from showing that there may be countervailing reasons to assess stranded costs broadly among all transmission customers (*e.g.*, where the costs assignable to a particular customer or group of customers may be so high as to create a dispute as to the propriety of direct assignment).

[628] *See, e.g.*, American Forest & Paper, Torco, Philip Morris, DE Muni, MT Com, IL Com, KS Com, Fertilizer Institute, Caparo, Las Cruces, IN Com, PA Munis, San Francisco, NRRI, Competitive Enterprise, ELCON, IN Industrials, UT Industrials, NY Energy Buyers, ABATE, CA Energy Co, Caparo, Education, Reynolds.

[629] *See, e.g.*, Fertilizer Institute, Caparo, DE Muni, PA Munis, MT Com, San Francisco, ELCON, IN Industrials, NY Energy Buyers.

[630] As used in this Rule, ''exit fee'' refers to the charge that will be payable by a departing generation customer upon the termination of its requirements contract with a utility (if the utility is able to demonstrate that it reasonably expected to continue serving the customer beyond the term of the contract), whether payable in a lump-sum payment or an amortization of a lump-sum payment. (The same charge also can be paid as a surcharge on the customer's transmission rate.)

Recognizing that each approach has advantages and disadvantages, we conclude that, on balance, direct assignment is the preferable approach for both legal and policy reasons.

One of the main reasons to adopt direct assignment of stranded costs is that direct assignment is consistent with the well-established principle of cost causation, namely, that the party who has caused a cost to be incurred should pay it. Direct assignment of stranded costs to departing generation customers is particularly appropriate given the nature of the stranded cost recovery mechanism contained in this Rule, which links the incurrence of stranded costs to the decision of a particular generation customer to use open access transmission to leave the utility's generation system and shop for power, and which bases the prospect of stranded cost recovery on the utility's ability to demonstrate that it incurred costs with the reasonable expectation that the customer would remain on its generation system.

A broad-based approach, in contrast, would violate the cost causation principle by shifting costs to customers (such as transmission users of the utility's system) that had no responsibility for stranding the costs in the first place. In addition, if the Commission were to adopt a broad-based approach, it would have to determine whether to base the transmission surcharge on all users of a utility's transmission system on a one-time, up-front estimate of stranded costs (that is, each utility claiming stranded costs would make a one-time, comprehensive determination of stranded costs for the utility as a whole) or on an as-realized basis (the surcharge would be based on actual customer departures and would be adjusted each time a customer departs). Each option would have disadvantages that are not present in the direct cost causation approach we are adopting.

For example, a major disadvantage of an up-front, broad-based transmission surcharge is that it in effect would charge customers for costs before the costs are incurred (*i.e.,* before customers have even decided to leave the utility's generation system) and could charge for costs that may never be incurred (*e.g.,* some customers may decide to stay on the utility's system as requirements customers). The other option, a broad-based transmission surcharge that would be adjusted as customers leave the utility's system, also has disadvantages. While this option might recover stranded costs that are closer to the actual amount incurred by the utility, it could produce variability in transmission rates every time stranded costs from a newly-departed customer are included in the transmission surcharge and, in turn, could possibly hamper efficient power supply choices and efficient generator location decisions. These disadvantages are not present in the direct assignment approach.

Direct assignment will result in a more accurate determination of a utility's stranded costs than would an up-front, broad-based transmission surcharge. This is because the stranded cost for any customer is finally determined only if that customer actually leaves a utility. Moreover, there is no stranded cost unless the then-current market price of power for the period that the utility reasonably expected to continue serving the customer is below the utility's cost. Thus, because the circumstances of each departing customer will be known, the amount of any stranded cost liability can be determined with reasonable accuracy. Further, if a customer does not leave the utility or leaves at some future time when the utility's costs are competitive, the issue need not be addressed.

On this basis, the direct assignment approach is more suited to the recovery of stranded costs as defined in this Rule (including the reasonable expectation standard and open access transmission causation requirement) than is a broad-based approach. We expect that a utility would have difficulty estimating in advance all of its stranded costs for purposes of an up-front, broad-based transmission surcharge. In the face of this uncertainty, the utility's best strategy likely would be to try to recover through the broad-based surcharge as much of its uneconomic assets as possible by claiming that all of its wholesale customers are likely to depart and to leave large stranded costs. In this regard, the broad-based approach would provide an incentive for a utility to try to recover the costs of all of its uneconomic assets whether or not they were prudently incurred. This is in contrast to what this Rule provides, which is for recovery of only those legitimate, prudent and verifiable costs that were incurred on behalf of a specific customer based on a reasonable expectation that the utility would continue to serve the customer and that are stranded when the customer departs the utility's generation system by using the utility's open access transmission.

The direct assignment approach also can be readily applied to both wholesale and retail-turned-wholesale departing customers. It also can be adapted for retail customers. Further, it works for costs stranded by a section 211 order requiring either a public utility, or a transmitting utility that is not also a public utility, to provide transmission service. However, this is not the case for a broad-based approach, particularly an up-front, broad-based approach. Assuming that a principal motivation for an up-front, broad-based approach would be to recover all of a utility's stranded costs as quickly as possible, retail-turned-wholesale stranded costs nevertheless are not susceptible of being collected on an up-front basis. It is not possible to make a realistic up-front estimate of costs stranded by municipalizations that may occur in the future. Thus, even if we were to adopt an up-front, broad-based approach for recovering costs that are stranded when wholesale requirements customers use their former supplier's transmission system to reach a new supplier, retail-turned-wholesale stranded costs would have to be identified as they occur and the stranded cost surcharge on transmission users adjusted accordingly. Similarly, the broad-based approach is not easily adaptable to transmitting utilities that are not also public utilities. It is doubtful that, in establishing the rate for a section 211 applicant, the Commission could also set transmission surcharges for customers that were not section 211 applicants; this is what a broad-based approach, in effect, would require us to do.

Direct assignment by means of an exit fee or a transmission surcharge that is not dependent on any subsequent power or transmission purchases by the customer is also an economically efficient way to collected stranded costs. The customer may make a lump-sum stranded cost payment, amortize the lump-sum payment, or spread the payment as a surcharge in addition to its transmission rate. The total amount of stranded costs that the directly-assigned customer ultimately pays would not depend on how much transmission service it takes and thus would not influence the customer's subsequent transmission purchase decisions.

With a broad-based surcharge (which could be demand- or usage-based), on the other hand, the surcharge for transmission users would depend on how much transmission service the users take. A broad-based approach also would be inefficient as it would raise the price of transmission service for all customers, thereby potentially cutting off some beneficial power trading that would otherwise occur for all unbundled transmission customers. The surcharge also could convert some profitable existing power purchase contracts into unprofitable contracts. In

addition, it could reduce economy trading because the surcharge would be added to the price of economy transmission. In this manner, a broad-based surcharge would constitute a cross-subsidy that could distort the market.

We recognize that direct assignment is not without its potential drawbacks. For example, when compared to an up-front, broad-based transmission surcharge approach, direct assignment may entail a longer stranded cost recovery period. The transition period for stranded cost recovery under a direct assignment approach would depend on the length of the remaining terms of the wholesale requirements contracts for which this Rule provides an opportunity for recovery (contracts executed on or before July 11, 1994 that do not contain an exit fee or explicit stranded cost provision).

On the other hand, a broad-based approach could identify and recover stranded costs earlier than the direct assignment approach; recovery of stranded costs for all of a utility's wholesale requirements customers could begin as soon as the utility's up-front stranded cost amount for departing wholesale customers is determined (through litigation or settlement). However, this potential advantage of a broad-based approach (the shorter transition period) is outweighed by what we believe to be a serious infirmity, namely, the possibility that the broad-based transmission surcharge could end up including costs that have not yet been incurred and may never be incurred.

In addition, another potential drawback to the direct assignment approach is that the departing generation customer may see little or no savings in the short-term by switching power suppliers once its stranded cost exit fee is added to its lower power price from a new supplier. Direct assignment may leave the customer uncertain about the benefits of shopping for power because of the customer's potential stranded cost liability and, in turn, may bias the customer toward staying with its existing power supplier.[631]

In the case of a broad-based approach, in contrast, much of the customer's direct assignment stranded costs are spread to others through a transmission surcharge. As a result, the departing generation customer's power cost savings may more than offset the customer's stranded cost transmission surcharge. The customer may therefore see earlier power cost savings if a broad-based approach were adopted.[632] Once again, however, we believe that this potential benefit to a broad-based approach is outweighed by a significant countervailing disadvantage. In particular, the potential power cost savings to the departing generation customer would be realized only by shifting costs (that are directly attributable to the departing generation customer) to the other users of the utility's transmission system. We believe that this negative aspect of a broad-based approach—its violation of the cost causation principle—is too great a price to pay for allowing a departing generation customer to realize power cost savings as early as possible.

Thus, we recognize that under direct assignment, it is possible that some customers may not be able to afford to leave as soon as they would like. This in turn could mean that lower cost suppliers would not be able to make sales to those customers as soon as they would like. However, this would occur only during a transition period, and it would ensure that, consistent with strict cost causation principles, the burden of these transition costs is not unfairly spread to other customers. Once the existing uneconomic assets and contracts are behind us, all wholesale customers will be better able to shop for power and reap the long-term benefits of competitive supply markets.

Although this direct assignment approach is different from the approach taken in the natural gas industry, we believe that the difference is justified. The transition of the electric industry to an open transmission access, competitive industry (including our proposal to allow an opportunity for extra-contractual recovery of stranded costs associated with a discrete set of wholesale requirements contracts) is different in a number of respects from the natural gas industry's transition to open access transportation service by interstate natural gas pipelines. The gas industry underwent a long period of open access transition, starting with Order No. 436 in 1985 and culminating with Order No. 636 in 1992. In the gas context, prior to addressing potential stranded costs, the Commission in Order No. 436 allowed customers receiving bundled gas sales and transportation service from a pipeline the option to convert to transportation-only service, or to reduce their contract demand for gas service, before the termination of their contracts with the pipeline.[633] As a result, most of the former bundled customers of the pipeline had already departed the pipeline's sales service before the Commission addressed the recovery of take-or-pay costs in Order Nos. 500 and 528. In addition, by the time that the Commission addressed the remaining transition costs in Order No. 636, the commodity or wellhead natural gas market was already competitive and the majority of gas was already being sold on an unbundled basis.

Thus, changes in the natural gas industry had progressed to such a point (*i.e.*, the departure of customers from bundled sales) that it was not possible for the Commission to use a strict cost causation approach. We noted in the Supplemental Stranded Cost NOPR that

> Many natural gas customers had already left their historical pipeline suppliers' systems. Others had converted from sales and transportation customers to transportation-only customers. Others were in a transition stage having had opportunities to lower their contract demands or otherwise become partial service customers. Significant take-or-pay and other costs had accumulated.[634]

Under those circumstances, the Commission determined that it was appropriate to spread the majority of the remaining transition costs associated with take-or-pay and other supply contracts to all customers (both existing and new) using the interstate natural gas transportation system. Moreover, because of the changes in contractual relationships that had already occurred among pipelines and their customers, it was no longer possible for the Commission to follow a strict cost causation approach to recovering take-or-pay costs. The Commission-prescribed remedy for the recovery of transition costs in the natural gas industry thus was tailored to fit the needs of that industry given the stage of development at the time.

However, such a broad-based approach to recovery of natural gas transition costs was an *exception* to the

[631] To counteract this potential disadvantage, we have provided procedures in this Rule, including a formula that the utility is to use to calculate a departing generation customer's stranded cost obligation, that allow a customer considering switching power suppliers to request a stranded cost determination from the utility at any time before the expiration of the customer's wholesale requirements contract. *See* Section IV.J.9.

[632] In addition, because the customer would already know its stranded cost transmission surcharge, it presumably would have some certainty as to the costs of shopping for power. However, the stranded cost surcharge in its transmission rates subsequently may be adjusted upward if the utility providing transmission becomes eligible to recover retail-turned-wholesale stranded costs. Also, if the broad-based stranded cost surcharge is adjusted on an as-realized basis, the potential departing generation customer's surcharge may increase as a result of other customers leaving the utility's system.

[633] As discussed in Section IV.A.5, we are not providing for a similar conversion right in this Rule.

[634] FERC Stats. & Regs. ¶32,514 at 33,108.

time-honored principle that rates should reflect cost causation, and because of this it was necessary for the Commission to justify its departure from that principle. As the court said in *K N Energy* v. *FERC,*[635] ''[i]t has been this Commission's long standing policy that rates must be cost supported. Properly designed rates should produce revenues from each class of customers *which match, as closely as practicable, the costs to serve each class or individual customer.''* In that case, the court found the Commission's departure from cost-causation justified ''given the unusual circumstances surrounding the take-or-pay problem, and the limited nature—both in time and scope—of the Commission's departure from the cost-causation principle.''[636] It continues to be Commission policy to follow the cost-causation principle to the extent possible.

The factors described above are not present in the electric industry. At this time, the vast majority of customers remain on their bundled suppliers' systems and generation is not yet fully competitive. Because the situation facing the electric industry today is different from that which the natural gas industry faced, the Commission must tailor its approach differently. In the case of the electric industry today, we have the opportunity to address the stranded cost recovery issue up front, before customers leave their suppliers' systems. We thus are able to use the cost causation approach that has been fundamental to our regulation since 1935.[637]

The Commission disagrees with commenters' arguments that we cannot impose an exit fee to recover stranded costs because we did not do so in the gas context. As discussed in Section IV.J.9, this Rule establishes procedures for providing a potential departing generation customer advance notice (*before* it leaves its existing supplier) of the stranded cost charge (whether it is to be paid as an exit fee or a transmission surcharge) that will be applied if the customer decides to buy power elsewhere. In the natural gas context, in contrast, the Commission has prohibited pipelines from developing and charging an ''exit fee'' *after* a customer had implemented its gas purchase decision, noting that otherwise, the customer would not know in advance the full cost consequences of its nomination decision.[638] The ''exit fee'' that the Commission rejected in *El Paso Natural Gas Company*[639] is also factually distinguishable from the ''exit fee'' discussed in this rule. In that case, the Commission rejected a pipeline's attempt post-restructuring to impose an ''exit fee'' on firm transportation-only customers (that were converted sales customers) who in the future elect either to terminate their firm transportation service upon expiration of the service agreement, or to reduce their firm transportation services level by more than 10 percent pursuant to an existing contractual reduction right. Such a scenario is quite different from the limited opportunity for stranded cost recovery provided in this Rule, which is based on a utility's reasonable expectation of continuing generation service to a bundled (sales and transmission) requirements customer.

We also will decline to require a utility seeking stranded cost recovery to shoulder a portion of its stranded costs. Such a requirement would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.[640] Although the Commission allowed such an approach with regard to a natural gas pipeline's take-or-pay costs,[641] we did so only as an extraordinary measure given the nature of the take-or-pay problem and the prevailing environment at that time. We returned to traditional principles when, in issuing Order No. 636, we authorized pipelines to recover all of their prudently incurred gas supply realignment costs (the costs pipelines incur in realigning, renegotiating, or terminating their portfolio of gas supply contracts to adjust to their sales customers' decisions to exercise their unilateral right under the rule to reduce or end their commodity purchase obligations to the pipelines).[642] In the case of the open access transmission required by this Rule, we believe that a utility is entitled to an opportunity to recover all legitimate, prudent and verifiable costs incurred by the utility when the availability of open access transmission enables a requirements customer to reach a new generation supplier.

Although the alternatives of either spreading the stranded costs to all transmission users or requiring the utility shareholders to share the costs with departing customers might enable a wholesale customer to leave sooner than would the direct assignment approach, the departing customer would be able to do so only at the expense of others who had no responsibility for causing the legitimate, prudent and verifiable costs to be incurred. Although we departed from strict cost causation principles in the gas context and required a broad spreading of the costs given the particular circumstances presented by the gas industry's transition to open access, we ultimately returned to the more traditional approach of allowing utilities to recover all of their prudently incurred transition costs in Order No. 636. At this juncture in the evolution of competition in the electric industry we need not make such a departure from cost causation principles; utilities can identify and seek to charge the customers who caused the costs to be incurred in the first place, before those customers leave the utility's generation system. Accordingly, we believe that a broader spreading of the costs to entities who are not responsible for the incurrence of

[635] 968 F.2d 1295, 1300–01 (D.C. Cir. 1992) (quoting Alabama Electric Cooperative, Inc. v. FERC, 684 F.2d 20, 27 (D.C. Cir. 1982) (emphasis in original).

[636] *Id.* at 1301. *See also* Public Utilities Commission of State of California v. FERC, 988 F.2d 154, 169 (D.C. Cir. 1993).

[637] Moreover, as we explained in the Supplemental Stranded Cost NOPR, the shifting of generation costs to transmission rates does not violate Commission policy where, as here, the customer that caused the costs to be incurred and stranded will continue to pay those costs. As we indicated, the only difference is that in some instances the customer will pay the costs through an adder to its transmission rate instead of through a generation rate. *See* FERC Stats. & Regs. ¶32,514 at 33,108 n.269.

[638] *See, e.g.,* Transwestern Pipeline Company, 43 FERC ¶61,240 at 61,654, *order on rehearing,* 44 FERC ¶61,164 at 61,536 (1988), *relevant petitions for review dismissed as moot,* Transwestern Pipeline Company v. FERC, 897 F.2d 570, 575–76 (D.C. Cir. 1990); El Paso Natural Gas Company, 47 FERC ¶61,108 at 61,314 (1989).

[639] 72 FERC ¶61,083 (1995). Further, VT DPS misinterprets the Commission's reference to the NOPR in that case. The Commission did not treat a notice of termination provision in El Paso's contract as a conclusive presumption that El Paso had no reasonable expectation of continuing to serve certain customers, as VT DPS contends. The Commission merely stated that ''[e]ven if the rules proposed in [the Supplemental Stranded Cost] NOPR were applied here, El Paso would have difficulty justifying the exit fee proposed in light of the existence of the notice of termination provision in the contract.'' 72 FERC at 61,441.

[640] *See, e.g.,* Maryland v. Louisiana, 451 U.S. 725, 748 (1981); Office of Consumers' Counsel v. FERC, 914 F.2d 292 (D.C. 1990); National Fuel Gas Supply Corporation v. FERC, 900 F.2d 340, 342, 347–51 (D.C. Cir. 1990).

[641] In Order No. 500, the Commission provided that if pipelines absorbed from 25 to 50 percent of their take-or-pay settlement costs, they could recover an equal amount from their firm sales customers in the form of fixed charges. Any balance could be recovered in the form of a commodity rate surcharge or a volumetric surcharge on total pipeline throughput. Order No. 500, FERC Stats. & Regs. ¶30,761 at 30,787 (1987). *See also* Order No. 528, 53 FERC ¶61,163 at 61,597 (1990). Moreover, we offered pipelines an important *quid pro quo* for absorbing take-or-pay costs under Order Nos. 500 and 528—a special presumption that they had been prudent in incurring their take-or-pay liabilities.

[642] Order No. 636, FERC Stats. & Regs. ¶30,939 at 30,461.

the stranded costs would not be equitable.

4. Recovery of Stranded Costs Associated With New Wholesale Requirements Contracts

In the Supplemental Stranded Cost NOPR, the Commission preliminarily concluded that future wholesale contracts must explicitly address the obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. We stated that utilities will be allowed stranded cost recovery associated with ''new'' wholesale requirements contracts (executed after July 11, 1994) only if *explicit* stranded cost provisions are contained in the contract. We indicated that recovery of wholesale stranded costs associated with any such new contract will not be allowed unless such recovery is provided for in the contract.[643] We also stated that a contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a ''new'' contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.[644]

We also stated that it is not appropriate to impose on a wholesale requirements supplier a regulatory obligation to continue to serve its existing requirements customer beyond the end of the contract term. We proposed to retain the § 35.15 prior notice of termination filing requirement only for: (i) All contracts required to be filed under sections 205 and 206 of the FPA that were executed before the effective date of the Final Rule pro forma tariffs; and (ii) any unexecuted contracts that were filed before the effective date of the Final Rule pro forma tariffs. With regard to any power sales contract executed on or after that date, we proposed to no longer require prior notice of termination under § 35.15, but to require (for administrative reasons) written notification of the termination of such contract within 30 days after termination takes place. We requested comments on whether this proposal should also be applied to transmission contracts.[645]

Comments

Numerous commenters support our preliminary conclusion that new wholesale requirements contracts should explicitly address the obligations of the seller and buyer and that it is not appropriate to impose on wholesale requirements suppliers a regulatory obligation to continue to serve their existing requirements customers beyond the end of the contract term.[646] However, Arkansas Cities expresses concern that this could undermine obligations to serve that have been included in certain contracts with utilities. It asks the Commission to state that, unless a utility has undertaken an obligation to serve via contract, there is no obligation to serve beyond the contract term. Arkansas Cities asks the Commission to clarify that contracts establishing an obligation to serve will be enforced.

Several other commenters argue that if a wholesale customer elects to switch suppliers, the previous supplier should be under no obligation to take the customer back onto its system at embedded cost rates.[647] Sierra asks the Commission to endorse a host utility's ability to insist on protective contract provisions before reestablishing service, including a predetermined period (such as five years—a commonly-used planning period) before the customer could seek to leave the system again.

A number of commenters support the Commission's proposal to eliminate the prior notice of termination requirement for power sales contracts executed after the date on which the final rule pro forma tariffs become effective.[648] Southern states that, because of the opportunities for power purchasers that will exist after the proposed rules take effect, the Commission also should eliminate § 35.15 as it applies to old contracts.

Several commenters support eliminating the § 35.15 filing requirement for transmission contracts as well.[649] This change is needed, some assert, to provide certainty in commercial arrangements in the more competitive environment and as a matter of fairness. CSW suggests that all § 35.15 filing requirements for existing contracts (wholesale and transmission contracts) be phased out over three years and that only contracts that expire within three years after the final rule should be subject to the requirement to file a notice of termination.

Nevertheless, several other commenters oppose the Commission's proposal to no longer require prior notice of termination for power sales contracts executed on or after the effective date of the generic tariffs.[650] TDU Systems opposes elimination of § 35.15 as tantamount to a finding that termination of all contracts is just and reasonable. TDU Systems and NRECA submit that the market power exercised by supplying utilities will not disappear the instant the rule becomes final and that it may be possible for a utility to exercise monopoly power even with regard to ''new'' contracts. They propose that if the Commission nevertheless decides to allow contract termination under § 35.15, the Commission should require a public utility to pay ''stranded benefit'' costs to former wholesale power customers if the customers show that they had a reasonable expectation that the power sales would continue past the end of the agreement at the prior rate.

Several commenters also oppose eliminating the § 35.15 filing requirement for transmission contracts.[651] FL Com asserts that because the Commission has imposed an obligation to serve for transmission service, § 35.15 should be retained for new and existing transmission contracts.

Commission Conclusion

We reaffirm our preliminary determination that future wholesale requirements contracts should explicitly address the mutual obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. As we indicated in the Supplemental Stranded Cost NOPR, now that utilities have been placed on explicit notice that the risk of losing customers through increased wholesale competition must be addressed through contractual means only, they must address stranded cost issues when negotiating new contracts or be held strictly accountable for the failure to do so.

We accordingly will allow recovery of wholesale stranded costs associated with any new requirements contract

[643] FERC Stats. & Regs. ¶ 32,514 at 33,110.

[644] *Id.* at 33,118.

[645] *Id.* and nn. 273, 274.

[646] *E.g.*, PA Com, FL Com, PSNM, Southern, NC Com, Duke, Public Service Co of CO, SoCal Edison, PacifiCorp, Carolina P&L, NYSEG.

[647] *E.g.*, Sunflower, Sierra, Public Service Co of CO, Duke.

[648] *E.g.*, EEI, NYSEG, Southern, PA Com, SoCal Edison, Pacificorp, El Paso.

[649] *E.g.*, EEI, Public Service Co of CO, PA Com, Entergy, Florida Power Corp.

[650] *E.g.*, TDU Systems, NRECA, TAPS, Redding, Southwest TDU Group. VT DPS sees no urgent need for elimination of the § 35.15 requirement or for automatic termination of sales service under a wholesale contract of more than three years duration. However, it supports pregranted authorization of service termination upon expiration of sales contracts with terms of less than three years. Among other things, it submits that the pregranted authority to terminate short-term service would relieve the utility of a planning uncertainty and allow it to maximize use of uncommitted transmission capacity.

[651] TAPS, TDU Systems, FL Com, MMWEC.

(executed after July 11, 1994) only if explicit stranded cost provisions are contained in the contract. By ''explicit stranded cost provision'' (for contracts executed after July 11, 1994) we mean a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate. For purposes of requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register, however, we clarify that a provision that specifically reserved the right to seek stranded cost recovery consistent with what the Commission permits in this Rule (without identifying the specific amount of stranded cost liability of the customer(s) and calculation method) nevertheless will be deemed an ''explicit stranded cost provision.'' However, a provision in a requirements contract executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that merely postpones the issue of stranded cost recovery without specifically providing for such recovery will *not* be considered an ''explicit stranded cost provision.'' After the date on which this Final Rule is published in the Federal Register, a provision must identify the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate in order to constitute an ''explicit stranded cost provision.''

We reaffirm that a requirements contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a ''new'' requirements contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.

We also reaffirm our preliminary determination not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers beyond the end of the contract term. The only exception to this would be if the customer decides to remain a requirements customer for the period for which the Commission finds that the supplying utility reasonably expected to continue serving the customer. In such a case, the supplying utility will be obligated to offer continuing service to the requirements customer for the period the utility reasonably expected to continue serving the customer.

A requirements customer will be responsible for planning to meet its power needs beyond the end of the contract term by either building its own generation, signing a new power sales contract with its existing supplier, or contracting with new suppliers in conjunction with obtaining transmission service under its existing supplier's open access transmission tariff or another utility's transmission system. In so holding, it is not our intent to undermine any obligations specifically contained in a contract. Thus, if a contract explicitly establishes an obligation to serve beyond the end of the contract term, such a contractually-imposed obligation to serve (as distinguished from a regulatory obligation to serve) would be enforceable as a term of the contract. If a wholesale customer that switches suppliers later seeks to reestablish service with its former supplier, it will be up to the parties to negotiate their respective obligations.

We also reaffirm our preliminary determination to no longer require prior notice of termination under § 35.15 for any power sales contract executed on or after the effective date of the Final Rule pro forma tariff (but to require written notification of the termination of such contract within 30 days after termination takes places). This determination goes hand-in-hand with our determination (discussed above) not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers beyond the end of the contract term.[652] We clarify, however, that this decision applies only to a power sales contract that is to *terminate by its own terms* (such as on the contract's expiration date). We have revised § 35.15 accordingly. We will, however, continue to require prior notice of cancellation or termination for any power sales contract that is proposed to be cancelled or terminated for a reason other than by the contract's own terms (such as a self-help provision related to, for example, a billing dispute), regardless of when the contract was executed. We also will continue to require prior notice of the proposed termination of any power sales contract executed before the effective date of the Final Rule pro forma tariff (even if the contract is to terminate by its own terms) as well as any unexecuted power sales contract that was filed before that date.

Further, we will retain the § 35.15 filing requirement for all transmission contracts. The reason for retaining the § 35.15 requirement for transmission contracts is that transmission will continue to be provided under conditions of potential market power, and the Commission must be assured that transmission owners are not exerting market power in termination of transmission contracts. In addition, this filing requirement will provide the customer an opportunity to notify the Commission if the termination terms are disputed or if the customer was not given adequate opportunity to exercise its limited right of first refusal under the Final Rule (*see* Section IV.A.5).

5. Recovery of Stranded Costs Associated With Existing Wholesale Requirements Contracts

In the Supplemental Stranded Cost NOPR, the Commission reaffirmed its proposal to permit the recovery of legitimate, prudent and verifiable stranded costs for a discrete set of ''existing'' wholesale requirements contracts (executed on or before July 11, 1994)—those that do not already contain exit fees or other explicit stranded cost provisions. We encouraged the parties to such contracts to renegotiate them to address stranded costs. In the case of existing contracts that already contain an exit fee or explicit stranded cost provision, however, we proposed to reject a unilateral stranded cost amendment; that is, we stated we would reject an amendment unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to renegotiate the contract.[653] In so doing, we proposed to drop the three year mandatory negotiation period suggested in the initial Stranded Cost NOPR.[654]

If an existing requirements contract does not contain an exit fee or other explicit stranded cost provision (and is not renegotiated to add such a provision), we proposed that before the expiration of the contract: (1) A public utility or its customer may file a proposed stranded cost amendment to the contract under section 205 or 206; or (2) a public utility or transmitting utility may file a proposal to recover stranded costs associated with any such existing contract through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier.

[652] Although several commenters have asked the Commission to retain the prior notice of termination filing requirement due to concern that a utility nevertheless may be able to exercise generation market power with regard to a ''new'' wholesale requirements contract, we do not believe that retention of that provision is necessary to address these commenters' concerns. Instead, any party claiming to be aggrieved by a utility's alleged abuse of generation market power under a wholesale requirements contract can file a complaint with the Commission under section 206 of the FPA.

[653] FERC Stats. & Regs. ¶ 32,514 at 33,113.

[654] We invited comments on this proposal. *Id.* at 33,115.

In the Supplemental Stranded Cost NOPR, we reaffirmed our proposal in the initial Stranded Cost NOPR that, even if the contract contains an explicit *Mobile-Sierra*[655] provision, it is in the public interest to permit public utilities to seek unilateral amendments to add stranded cost provisions if the contracts do not in essence forbid such recovery by containing exit fees or other explicit stranded cost provisions.[656] Under these circumstances, if neither of the parties seeks and obtains acceptance or approval of a stranded cost amendment, we propose to permit the public utility to seek recovery of stranded costs through its wholesale transmission rates.

We also proposed procedures for providing an existing wholesale requirements customer advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[657]

Comments

a. July 11, 1994 Cut-Off Date

A number of commenters ask the Commission to reconsider the July 11, 1994 cut-off date for distinguishing between ''existing'' and ''new'' requirements contracts. Some commenters[658] support October 24, 1992 (the date of passage of the Energy Policy Act) as the cut-off date on the basis that anyone entering into a wholesale requirements contract after that date should have recognized the greatly increased possibility of the customer terminating or not renewing the contract.

Other commenters[659] support a later date for defining ''new'' requirements contracts, such as the date on which the final rule open access tariffs become effective. Utilities For Improved Transition argues that the Commission cannot retroactively adopt the July 11, 1994 cut-off date, but must wait until the final rule is issued before setting the date after which requirements contracts must contain stranded cost provisions in order for stranded cost recovery to be allowed.

Commenters representing electric cooperatives also oppose the July 11, 1994 cut-off date.[660] They contend that RUS borrowers were not free to negotiate stranded cost amendments to wholesale power contracts as soon as the Commission warned them to do so because their wholesale power contracts are mandated both as to form and substance by the RUS.[661]

PA Munis asks the Commission to treat certain contracts that were executed before July 11, 1994 (but not approved by the Commission until after that date) as ''new'' contracts. PA Munis argues that the utility, after issuance of the initial NOPR, could have withdrawn its filing of the contract and sought to negotiate an exit fee at that time. It submits that the utility's failure to do so would justify a finding by the Commission that contracts *approved* after July 11, 1994 be treated similarly to contracts executed after that date.

b. Stranded Cost Recovery for Existing Requirements Contracts

A number of commenters express support for the Commission's proposal to permit modification of existing requirements contracts that do not already contain exit fees or other explicit stranded cost provisions.[662] NEPCO states its interpretation that the NOPR does not consider notice provisions to be ''explicit stranded cost provisions;'' it argues that the presence of a notice provision in a contract, while bearing on the supplier's ability to demonstrate the duration of its reasonable expectation of continued service, should not foreclose the amendment of a wholesale contract to add an exit fee or similar payment provision. Several other commenters ask the Commission to clarify that contracts that contain notice provisions and that preclude recovery for termination or reduction of service (but that do not necessarily use the terms ''exit fee'' or ''stranded cost''), or that expressly provide that stranded costs shall not be charged, cannot be reopened for a stranded cost claim.[663]

A number of other commenters oppose the Commission's proposal to permit amendment of wholesale requirements contracts that do not address stranded cost recovery, for reasons previously raised in this proceeding.[664] They argue, among other things, that contracts should stand on their own. RUS asserts that the integrity of its Federal loan program is to a large extent predicated on honoring the long-term requirements wholesale power contracts between G&Ts and their distribution members.

Several commenters also challenge the Commission's proposed determination that it is in the public interest to permit utilities to seek unilateral amendments to add stranded cost provisions to requirements contracts. These commenters argue that the NOPR's assumptions concerning the financial stability of public utilities are unsupported and thus do not meet the burden of proof required for the public interest finding under the *Mobile-Sierra* doctrine. They urge the Commission to require a utility-specific finding of imminent financial jeopardy before overriding a *Mobile-Sierra* contract.[665]

ELCON argues that the recent *Northeast Utilities Service Company* v. *FERC*[666] case reaffirms the traditional high threshold for overriding *Mobile-Sierra* clauses in the ''classic *Mobile-Sierra* situation'' in which one of the parties seeks modification of a contract that has already been reviewed and approved by the Commission. It submits that a utility seeking to add a stranded cost provision to an existing contract would fall within the ''classic situation.'' ELCON also argues that the First Circuit strongly implied that to satisfy *Mobile-Sierra*, the Commission must identify specifically those aspects of a contract that are contrary to the public interest and why. On this basis, ELCON argues that the case supports its position that a utility-specific finding of imminent financial jeopardy is necessary to override an existing *Mobile-Sierra* contract.[667]

[655] *See* United Gas Pipeline Company v. Mobile Gas Service Corporation, 350 U.S. 332 (1956); FPC v. Sierra Pacific Power Company, 350 U.S. 348 (1956).

[656] FERC Stats. & Regs. ¶ 32,514 at 33,113–14. We noted that under the *Mobile-Sierra* doctrine, a customer may waive its right to challenge the contract and/or the utility may waive its right to make unilateral rate changes. However, the parties may not waive the indefeasible right of the Commission to alter rates that are contrary to the public interest. *Id.* at 33,111.

[657] *Id.* at 33,114–15.

[658] *E.g.*, ELCON, TAPS, Alcoa, Utilicorp.

[659] *E.g.*, Utilities For Improved Transition, Atlantic City.

[660] *E.g.*, Basin, Tri-County EC, NW Iowa Cooperative, Baker EC, Big Horn EC, Black Hills EC, Bon Homme Yankton EC, Carbon Power, Central EC, Douglas EC, East River EC, Ida County REC, James Valley EC, Lincoln-Union EC, McKenzie EC, North Dakota RECs, Oahe EC, Oliver-Mercer EC, Panhandle Coop, Rushmore EC, San Luis Valley EC, Slope EC, Spink EC, Turner-Hutchinson EC, Traverse EC, Union County EC, West River EC, Whetstone Valley EC, Woodbury County REC, Yellowstone Valley EC.

[661] Basin indicates that all such contracts for the sale of more than 1,000 kW and any amendments thereto must be specifically approved by the RUS.

[662] *E.g.*, EEI, PSNM, AEP, Consumers Power. Consumers Power suggests that the language of proposed § 35.26(c)(1)(iv) be modified to recite the Commission's public interest finding.

[663] *E.g.*, Concord, Chugach, ME Consumer-Owned Utilities.

[664] *E.g.*, Utilicorp, AMP-Ohio, Environmental Action, DE Muni, Arkansas Cities, Direct Service Industries, PA Munis, ABATE, APPA.

[665] *See, e.g.*, American Forest & Paper, VT DPS, PA Munis, ABATE, ELCON, APPA, Environmental Action.

[666] 55 F.3d 686 (1st Cir. 1995) (*Northeast Utilities*).

[667] PA Munis argues that *Northeast Utilities* provides no support for the Commission's proposed *Mobile-Sierra* finding because *Northeast Utilities* involved the effect of disputed contractual terms on

Some commenters argue that if utilities are to be granted industry-wide *Mobile-Sierra* relief, then the Commission should give wholesale customers the reciprocal right to convert their wholesale power contracts to transmission-only service.[668] However, EEI contends that the Commission is barred by section 211(c)(2) of the FPA from ordering wheeling where a customer is taking service under a contract or under a rate tariff on file with the Commission.

Several commenters ask the Commission to require renegotiation of the notice and/or term of all existing contracts with long lead-time cancellation provisions in order to allow all wholesale customers access to the market at the same time.[669] They submit that customers with short notice provisions will be the first to enjoy the benefits of open access and will have an effective ''first right of refusal'' of the most economical transmission paths and low cost suppliers, putting customers with long lead-time cancellations at a competitive disadvantage.

c. Transition Period

A number of commenters support the Commission's proposal not to mandate a three-year time limit for renegotiation of existing wholesale requirements contracts. They note that existing contracts have unique characteristics and complexities that affect the time required to renegotiate the contract bilaterally, to file a unilateral amendment with the Commission, or to file for stranded cost recovery through transmission rates.[670]

On the other hand, some commenters object that the proposal to replace the previously proposed three-year window with an opportunity to raise stranded cost claims throughout the existing contract term creates a virtually unlimited transition period.[671] For example, ELCON asserts that because the NOPR would allow utilities to seek amendment of an existing contract any time prior to its expiration, stranded cost issues could extend through the life of existing facilities (30 years or more). Portland suggests that the Commission set a schedule now for proceedings to determine transmission costs and stranded costs for each utility with wholesale requirements customers.

Commenters propose various limits to the period within which stranded cost recovery could be raised, such as: (i) Three to five years;[672] (ii) the lesser of three years from the effective date of the final rule or the remaining term of the contract;[673] (iii) one year from the effective date of the final rule;[674] and (iv) December 31, 1998 (20 years after PURPA).[675]

Commission Conclusion

a. July 11, 1994 Contract Cut-Off Date

We reaffirm our proposal to permit the recovery of legitimate, prudent and verifiable stranded costs for ''existing'' wholesale requirements contracts (executed on or before July 11, 1994) that do not already contain exit fees or other explicit stranded cost provisions. We believe that July 11, 1994—the date on which the initial Stranded Cost NOPR was published and, thus, on which the industry was put on notice of the proposal to disallow prospectively extra-contractual recovery of stranded costs—is the appropriate date for distinguishing ''existing'' requirements contracts from ''new'' requirements contracts. Because all parties were put on notice in the initial Stranded Cost NOPR that July 11, 1994 would be the operable date for the ''existing''/''new'' contract distinction, utilities that executed requirements contracts after that date could have had no reasonable expectation that they would be permitted to recover any costs extra-contractually.

Moreover, because the costs at issue are extra-contractual costs, the Commission's notice to all parties that contracts executed after July 11, 1994 will be enforced by their terms as far as stranded cost recovery is concerned does not constitute ''retroactive rulemaking.'' Contrary to UFIT's contention, the Commission is not ''requir[ing]'' utilities to include stranded cost recovery provisions in all contracts executed after July 11, 1994.[676] The Commission has merely put all parties on notice that the opportunity for extra-contractual stranded cost recovery (which will be allowed on a prospective basis upon the effective date of the Rule) will not be available for any requirements contracts executed after July 11, 1994. The parties to requirements contracts executed after July 11, 1994 have been free to provide for stranded cost recovery in the contract, or not.[677] The point is that, for requirements contracts executed after the cut-off date, stranded cost recovery will be governed solely by the terms of the contract.

b. Stranded Cost Recovery for Existing Requirements Contracts

We reaffirm that we will permit utilities to seek recovery of stranded costs for a limited set of existing wholesale requirements contracts, namely, those that do not already contain exit fees or other explicit stranded cost provisions.[678] If an existing requirements contract includes an explicit provision for payment of stranded costs or an exit fee, we will assume that the parties intended the contract to cover the contingency of the buyer leaving the system. We will reject a stranded cost amendment to such a contract, unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to a new stranded cost provision. Similarly, we will reject a stranded cost amendment to an existing requirements contract if the contract prohibits stranded cost recovery (or precludes recovery for termination or reduction of service) or

third parties, not the alleged financial effect on the utility. It argues that the court found that the Commission had adequately explained how the disputed contractual terms may harm third parties to the contract (which PA Munis says the Commission has failed to do here). PA Munis also submits that the court went out of its way to emphasize the narrow scope of its order affirming the Commission.

[668] *E.g.*, ELCON, CCEM, VT DPS, OK Com, TDU Systems, LG&E, ABATE, Portland, Utilicorp, TAPS.

[669] *E.g.*, Knoxville, Memphis.

[670] *E.g.*, EEI, Florida Power Corp, PA Com, WP&L, Consumers Power, FL Com, TVA, SoCal Edison, Texas Utilities.

[671] *E.g.*, TAPS, TDU Systems, DOD, ELCON, APPA.

[672] *E.g.*, Sierra, Central Illinois Light, NY Energy Buyers, American Forest & Paper, WEPCO, EGA. Education proposes either a transition period that ends five years after the effective date of the final rule or a phase-out of the utility's authority to recover stranded costs from departing customers by gradually reducing (for instance, over a ten year period from the date of the final rule) the percentage of stranded costs that the utility could recover.

[673] *E.g.*, TAPS, Missouri Joint Commission.

[674] *E.g.*, TDU Systems.

[675] *E.g.*, DOD, ABATE.

[676] See UFIT Initial Comments at 34. Moreover, the cases that UFIT cites, in which the Commission rejected parties' efforts to devise rates based on methods or formulas contained in proposed rules, are inapposite. By establishing the July 11, 1994 cutoff date, the Commission is not ''fix(ing) rates under section 206'' or otherwise making ''a Section 206 'determination,'" as UFIT suggests. *Id.* at 35, 36. The Commission has not proposed a change in the way that utilities compute their rates; it has simply put all parties on notice of the limited nature and opportunity for extra-contractual stranded cost recovery.

[677] In response to the commenters representing electric cooperatives that object to the July 11, 1994 cut-off date, we do not believe that the requirement that RUS borrowers obtain RUS approval of their contracts necessarily prevents such borrowers from addressing stranded cost recovery in contracts executed after July 11, 1994.

[678] We confirm that a notice of termination provision by itself (that is, one that does not also provide for or preclude recovery of stranded costs by the seller upon termination of the contract) is not an ''explicit'' stranded cost provision; however, as discussed in Section IV.J.8, the presence of a notice provision creates a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer.

prohibits renegotiation of an existing stranded cost or exit fee provision, unless the parties to the contract mutually agree to a new stranded cost provision.[679]

We reaffirm our desire that utilities attempt to renegotiate with their customers existing requirements contracts that do not contain exit fees or other explicit stranded cost provisions. If the parties negotiate a stranded cost provision and the seller is A public utility, the utility must file the provision with the Commission as an amendment to the existing requirements contract.

If an existing requirements contract does not contain an exit fee or other explicit stranded cost provision (and is not renegotiated to add such a provision), before the expiration of the contract: (1) a public utility or its customer may file a proposed stranded cost amendment to the contract under section 205 or 206; or (2) a public utility in a section 205 proceeding, or a transmitting utility in a section 211 proceeding, may file a proposal to recover stranded costs associated with any such existing contract through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier.

We thus reaffirm that if an existing requirements contract is not renegotiated, and the contract permits the seller and/or buyer to seek an amendment to the contract, the authorized party may seek an amendment to add a stranded cost provision. We also adopt our preliminary finding that, even if an existing requirements contract contains an explicit *Mobile-Sierra* provision, it is in the public interest to permit the public utility to seek a unilateral amendment to add stranded cost provisions if the contract does not already contain exit fees or other explicit stranded cost provisions. In the initial Stranded Cost NOPR, we identified two ways in which a failure to permit public utilities to address stranded costs could harm third parties, and thereby harm the public interest:

First, the inability to seek recovery of stranded costs could impair the financial ability of a utility to continue to provide reliable service. This will depend on the magnitude of stranded costs and the prospect or lack thereof for recovering such costs from ratepayers. The prospect of not recovering from ratepayers significant amounts of stranded costs could seriously erode a utility's access to capital markets, or could drive the utility's cost of capital to unprecedented levels. This high cost of capital could precipitate other customers leaving the system which, in turn, could cause others to leave. Such a spiral could be difficult to stop once begun. Second, if some customers are permitted to leave their suppliers without paying for stranded costs, this may cause an excessive burden on the remaining customers who, for whatever reason, cannot leave and therefore may have to bear those costs.[680]

The financial community commenters confirm our views in this regard. As they note, a utility's access to financial markets is essential to the continued provision of safe and reliable electric service to customers. However, the prospect of a utility not recovering stranded costs could erode a utility's ability to attract capital and thus imperil its continued financial stability.[681] As these and other commenters agree, the recovery of stranded costs is critical to the successful transition to more competitive markets.

Moreover, our determination that it is in the public interest to give public utilities a limited opportunity to propose contract changes unilaterally to address stranded costs if their contracts do not already explicitly do so satisfies the public interest standard of the *Mobile-Sierra* doctrine as recently interpreted by the *Northeast Utilities* court. In that case, the court affirmed an order of the Commission on remand modifying a contract under the *Mobile-Sierra* public interest standard.[682] As the court explained, the *Mobile-Sierra* doctrine ''represents the Supreme Court's attempt to strike a balance between private contractual rights and the regulatory power to modify contracts when necessary to protect the public interest.''[683] The court noted that when the Commission is considering whether a contract rate is too low, protective action by the Commission in the public interest is justified ''where the rate might impair the financial ability of the utility to continue to supply electricity, force electricity consumers to bear an excessive burden, or be unduly discriminatory.''[684]

The court also explained that ''the most attractive case for affording additional protection [under the public interest standard], despite the presence of a contract, is where the protection is intended to safeguard the interests of third parties * * *.' ''[685] It stated that the *Mobile-Sierra* doctrine allows the Commission to modify the terms of a private contract ''when third parties are threatened by possible 'undu[e] discrimination' or the imposition of an 'excessive burden.' ''[686] The court found that the Commission had met the public interest standard by showing how the contract could harm *third parties*.[687]

Consistent with the holding in *Northeast Utilities*, and contrary to the positions of some commenters, we have demonstrated how ''*third parties* may ultimately bear the burden''[688] if public utilities with *Mobile-Sierra* contracts are not given any opportunity to propose contract changes to address stranded costs. If the Commission fails to give a

[679] In the case of an existing wholesale requirements contract that does not contain an exit fee or other explicit stranded cost provision but does contain a notice provision, once a customer gives notice according to the terms of the contract that it will no longer purchase all or a part of its requirements from the selling utility, we would not allow the utility to amend the contract to add a stranded cost provision. However, in such a case, the utility could seek to recover stranded costs through its rates for transmission services to the customer. As discussed in Section IV.J.8, the utility would have to rebut the presumption that, based on the presence of the notice provision, it had no reasonable expectation of continuing to serve the customer.

[680] FERC Stats. & Regs. ¶ 32,507 at 32,870.

[681] *See* Utility Investors Analysts, Initial Comments at 2–3; Utility Shareholders, Initial Comments at 2–4.

[682] The court concluded that the Commission ''gave thoughtful consideration to the public interest.'' 55 F.3d at 693.

[683] *Id.* at 689.

[684] *Id.* at 690.

[685] *Id.* at 691, citing Northeast Utilities Service Company v. FERC, 993 F.2d 937, 961 (1st Cir. 1993).

[686] *Northeast Utilities*, 55 F.3d at 691. The court distinguished the facts of that case from other *Mobile-Sierra* cases. It noted that ''[t]he issue here is not whether one party to a rate contract filed with FERC can effect a rate change unilaterally, but the standard to be used by FERC in examining electric power contracts filed with it.'' *Id.* at 690–91. It also noted that the contract provisions under review were not low-rate issues in the context of *Mobile* and *Sierra*. We recognize that whether a contract should be modified to add a stranded cost provision could be viewed as one party to a contract seeking to effect a unilateral rate change, or as a low-rate issue (*i.e.*, whether the utility's rates would be insufficient without stranded cost recovery). However, parties are being permitted to make such unilateral filings only after a generic finding by the Commission that the public interest likely would be jeopardized if utilities are not permitted to make a case-specific showing that recovery should be allowed. We believe that *Northeast Utilities* provides valuable guidance concerning application of the public interest standard where, as here, a failure to allow limited contract modification may harm the public interest by harming third parties.

[687] The court found that the Commission had met the public interest standard ''by explaining how the disputed contractual terms may harm third parties to the contract. * * * For example, the Commission found the automatic rate-of-return-on-equity adjustment provision unacceptable because *third parties* may ultimately bear the burden of a rate component that does not reflect actual capital market conditions. Likewise, the 'blank check' given owners of the power plant to determine the decommissioning costs for themselves under New Hampshire law is impermissible because it may be cashed at the expense of non-parties to the contract.'' *Id.* at 692 (emphasis in original). The court rejected the argument that the public interest standard is ''practically insurmountable'' in all circumstances. It noted, among other things, ''that neither *Mobile* nor *Sierra* stated or intimated that the 'public interest' doctrine was 'practically insurmountable.' '' *Id.* at 691.

[688] *Id.* at 692 (emphasis in original).

public utility this opportunity, and the utility's financial ability to continue the provision of safe and reliable service is impaired, third parties (customers relying on the public utility for their electric service) will be placed at risk. Similarly, if the Commission fails to give a public utility the opportunity to directly assign costs to the customers on whose behalf they were incurred, and some of the utility's customers leave the utility's generation system for that of another supplier without paying such costs, third parties (the utility's remaining customers) will be harmed by having to bear the costs that were not incurred to serve them and that are stranded by the other customers' departures via open access transmission. Moreover, we believe that protective action in the public interest is particularly necessary where, as here, a utility's rates could become insufficient because of fundamental changes in the industry that largely result from legislative or regulatory changes that could not be anticipated.

Further, notwithstanding the arguments of some commenters supporting a case-by-case (as opposed to a generic) public interest finding, we believe it appropriate that our public interest finding be made on a generic basis given the fact that, by this Rule, we are requiring full open access that could significantly affect historical relationships among traditional utilities and their customers and the ability of utilities to recover prudently incurred costs. We also emphasize that we are not eliminating the need for case-by-case demonstrations that stranded cost recovery should be allowed. Our public interest finding is that utilities be permitted to *seek* extra-contractual recovery of stranded costs in certain defined circumstances. Utilities seeking recovery of stranded costs will have the burden, on a case-by-case basis, of showing they had a reasonable expectation of continuing to serve the departing generation customer.

In summary, we emphasize the limited nature of our *Mobile-Sierra* public interest finding. First, our holding applies only to wholesale requirements contracts executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision. Thus, we will not permit modification of any contract that addresses the stranded cost issue explicitly, unless the contract specifically permits such modifications. Instead, we are simply examining requirements contracts that do not clearly address the issue in the context of the traditional regulatory regime under which they were signed—a regulatory environment in which it was assumed as a matter of course that the great majority of requirements customers would stay with their original suppliers and that these suppliers had a concomitant obligation to plan to supply these customers' continuing needs.

Second, although we have decided on a generic basis that it is in the public interest to permit public utilities with *Mobile-Sierra* contracts to make unilateral filings, we are not automatically approving any amendment that a particular utility might file. As we stated in the initial Stranded Cost NOPR, if a public utility unilaterally files a proposed stranded cost amendment under either section 205 or 206 of the FPA, this does not necessarily mean that the Commission ultimately will find it appropriate to allow such amendment.[689] In addition, customers with *Mobile-Sierra* contracts that do not explicitly address stranded costs may also file complaints under section 206 of the FPA to propose to address stranded costs in existing requirements contracts. The Commission will analyze any proposed stranded cost amendment to a *Mobile-Sierra* contract, whether proposed by the utility or by its customer, based on the particular circumstances surrounding that contract. Thus, the case-by-case findings that some commenters seek will, in effect, be made when the Commission determines whether to approve a proposed stranded cost amendment to a particular contract.

As discussed in Section IV.A (Scope), the Commission has concluded that although current conditions in the wholesale power market do not warrant the generic modification of requirements contracts, nonetheless the modification of certain requirements contracts on a case-by-case basis may be appropriate. We have concluded further that, even if customers under such contracts are bound by so-called *Mobile-Sierra* clauses, they nonetheless ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

We have found that it would be against the public interest to permit a *Mobile-Sierra* clause in an existing wholesale requirements contract to preclude the parties to such a contract from the opportunity to realize the benefits of the competitive wholesale power markets. For purposes of this finding, the Commission defines existing requirements contracts as contracts executed on or before July 11, 1994.[690] By operation of this finding, a party to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract. The party, however, still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified.

This finding complements the Commission's finding that, notwithstanding a *Mobile-Sierra* clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of this Rule. The Commission's complementary *Mobile-Sierra* findings are not mutually exclusive. Any contract modification approved under this section shall provide for the utility's recovery of any costs stranded consistent with the contract modification. The stranded costs must be prudently incurred, legitimate and verifiable. Further, the Commission has concluded that if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.

The Commission believes that the most productive way to analyze contract modification issues is to consider simultaneously both the selling public utility's claims, if any, that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and the customer's claim, if any, that the contract no longer is just and reasonable and therefore ought to be modified. Thus, if the selling public utility intends to claim stranded costs, it must present that claim in any section 206 proceeding brought by the customer to shorten or terminate the contract. Similarly, if the customer intends to claim that the notice or termination provision of its existing requirements contract is unjust and unreasonable, it must present that claim in any proceeding brought by the selling public utility to seek recovery of stranded costs. This will promote administrative efficiency and will permit the Commission to consider how the contracting parties' claims bear on one another.

[689] FERC Stats. & Regs. ¶ 32,507 at 32,871.

[690] This is consistent with the definition of existing requirements contracts we have used for purposes of stranded cost recovery.

The Commission does not take contract modification lightly. Whether a utility is seeking a contract amendment to permit stranded cost recovery based on expectations beyond the stated term of the contract, or a customer is seeking to shorten or eliminate the term of an existing contract, we believe that each have a heavy burden in demonstrating that the contract ought to be modified. Still, we believe that given the industry circumstances now facing us, both selling utilities and their customers ought to have an opportunity to make the case that their existing requirements contracts ought to be modified. By providing both buyers and sellers this opportunity, the Commission attempts to strike a reasonable balance of the interests of all market participants. The Commission expects that many of the arguments presented by buyers and sellers in such proceedings will be fact specific.

c. Transition Period

We reaffirm our proposal to allow a public utility or its customer to file a proposed stranded cost amendment, or to allow a public utility or transmitting utility to file a proposal to recover stranded costs through a departing generation customer's transmission rates, at any time prior to the expiration of the contract. There is no uniform time remaining on requirements contracts executed on or before July 11, 1994. Any limitation on the period in which parties could propose amendments covering stranded costs (*e.g.*, 3 years) would thus unequally affect market participants. Those with long terms remaining on their contracts could object that immediately addressing the issue would not be cost effective. For example, a utility with a long remaining term (*e.g.*, 20 years) might not even seek stranded cost recovery depending on the competitive value of its assets near the end of the contract term.[691] However, such a utility would invariably seek to preserve its option to seek stranded cost recovery if its failure to do so within a short period resulted in a waiver of its right to do so.

6. Recovery of Stranded Costs Caused by Retail-Turned-Wholesale Customers

In the Supplemental Stranded Cost NOPR, we stated that both this Commission and state commissions have the legal authority to address stranded costs that result from retail customers becoming wholesale customers who then obtain transmission under the open access tariffs.[692] We proposed that this Commission should be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. We explained that if a retail customer becomes a legitimate wholesale customer (such as through municipalization), it becomes eligible to use the non-discriminatory open access tariffs:

> If costs are stranded as a result of this wholesale transmission access, we believe that these costs should be viewed as 'wholesale stranded costs.' But for the ability of the new wholesale entity to reach another generation supplier through the FERC-filed open access transmission tariff, such costs would not be stranded.[693]

We accordingly proposed to define ''wholesale stranded costs'' to include stranded costs resulting from unbundled transmission for newly-created wholesale customers and sought comments on this definition.

We proposed to require the same evidentiary demonstration for recovery as that required if recovery were sought from a wholesale requirements customer. We reaffirmed our proposal in the initial Stranded Cost NOPR that a utility will have to show that the stranded costs are not more than the net revenues that the retail-turned-wholesale customer would have contributed to the utility had it remained a retail customer of the utility, and that the utility has taken and will take reasonable steps to mitigate stranded costs. We further proposed to deduct any recovery that a state has permitted from departing retail-turned-wholesale customers from the legitimate stranded costs of which we will allow recovery. In addition, we proposed to apply the same procedures for obtaining an estimate of maximum stranded cost exposure without mitigation to retail customers contemplating becoming wholesale transmission customers as those proposed for wholesale customers.[694]

Comments

Some commenters contend that stranded costs that result when a retail customer becomes a wholesale customer should be left to the states as a matter of law and comity.[695] These commenters argue, among other things, that because the facilities used to provide retail service to these retail customers were subject to state jurisdiction and were included in retail rate base when the service was rendered, the state is the appropriate entity to determine the extent to which those customers should compensate the utility for the stranding of these costs. According to ELCON, ''(a) retail customer's new found access to the wholesale market does not provide FERC with authority over costs that originated with the local distribution function.'' [696]

Commenters assert that stranded costs resulting from the creation of new wholesale entities will occur as a result of state or local decisionmaking.[697] A number of commenters contend that in states where the state commission has control over municipalization, the Commission has no authority to provide for the recovery of stranded costs due to municipalization.[698] IL Com asserts that the Commission lacks authority over retail-turned-wholesale stranded costs, even in the absence of any explicit statutory authority for state commissions to address such costs. FL Com argues that the Commission should address the recovery of these stranded costs only upon petition from a state public utility commission.

According to some commenters, the availability of open access transmission tariffs does not convert the character of the costs of stranded generation that was built to serve retail customers from retail to wholesale.[699] CA Com argues that this reasoning could require the Commission to act as the primary forum for stranded costs resulting from retail wheeling if the Commission's jurisdiction over retail transmission is upheld. It argues that in such a case, there also would be a relationship between the Commission-jurisdictional transmission and stranded costs.

Some commenters also submit that the potential for retail customers to become wholesale customers has existed since the beginning of the industry and that utilities have had ample opportunity to adjust to this risk.[700] A number of commenters submit

[691] The value of its assets could vary over time as new technologies emerge, fuel costs fluctuate, or environmental requirements change.

[692] FERC Stats. & Regs. ¶ 32,514 at 33,127.

[693] *Id.* at 33,128.

[694] *Id.*

[695] *E.g.*, NARUC, ELCON, TAPS, NASUCA, N.Y. Mayors, NY Industrials, American Iron & Steel, Missouri Joint Commission, Omaha PPD, MI Com, NY Com, NJ BPU, VT DPS, OK Com, IN Com, UT Com, WA Com, Environmental Action, IN Industrials, LA DWP, Seattle, CAMU, Las Cruces, UT Industrials, Suffolk County, NM Industrials, CO Consumers Counsel.

[696] ELCON Comments, dated July 25, 1995, at 41.

[697] *E.g.*, MD Com, MI Com, LA DWP, Las Cruces. For example, MD Com states that while open access transmission may make municipalization more attractive, it ultimately is MD Com's approval that makes municipalization possible in Maryland.

[698] *E.g.*, MD Com, Las Cruces, Caparo, Coalition on Federal-State Issues, IN Com, MI Com, Iowa Board.

[699] *E.g.*, IL Com, CA Com, Midwest Commissions, CO Consumers Counsel.

[700] *E.g.*, LA DWP, Ohio Manufacturers, MMWEC, American Iron & Steel, UT Industrials, MI Com, NY Industrials, WA Com, Caparo.

that state commissions are in a better position than the Commission to address the recovery of costs that were incurred to serve retail customers and to take into consideration local concerns.[701]

NARUC recognizes that a ''practical regulatory gap may exist that prevents [state commission] consideration of recovery of * * * potentially stranded costs'' in certain instances ''such as municipalization and cooperatives, where retail customers become wholesale customers under a FERC-approved open access tariff, [and] costs of the utility which served the customer at retail may become stranded.'' [702] NARUC proposes that the affected states and the Commission collaboratively develop mechanisms (which may involve amendments to the FPA, state statutes, or both) to eliminate these regulatory gaps.

Some commenters object that the Commission's proposal to be the primary forum for recovery of stranded costs caused by retail-turned-wholesale customers would make municipalization more expensive and therefore would discourage municipalities from seeking alternative sources of electricity.[703] Some argue that different treatment of stranded costs between federal and state authorities may lead to forum-shopping as a primary determinant in the decision to municipalize.[704]

A number of commenters also suggest that the NOPR is inconsistent with prior Commission treatment of municipalization because the Commission has historically promoted franchise competition between municipalities and utilities and has never before suggested that utilities could ''penalize'' municipalization decisions through generation cost add-ons to transmission rates.[705] VT DPS states: ''By the Commission's logic, there would never have been an *Otter Tail* case. If Otter Tail could have made a stranded cost claim against the municipal utility Elbow Lake planned to create, Otter Tail would never have needed to refuse to wheel.'' [706]

Suffolk County states that the Commission already considered stranded costs in the context of retail-turned-wholesale customers in *United Illuminating Company*,[707] where the Commission required United Illuminating to remove a provision in its proposed transmission tariff that would have allowed it to recover stranded costs associated with former retail loads served by new municipal systems. Suffolk County states that the Commission made clear that stranded cost matters, including those caused by municipalization, properly would be raised before state regulatory authorities. It objects that the Open Access NOPR ignores this case. Suffolk County also submits that the Commission's adoption of the settlement approved by the Massachusetts DPU in the Massachusetts Bay Transportation Authority case should serve as an example of proper jurisdictional deference with respect to local issues.[708]

However, many other commenters support the Commission's proposal to be the primary forum for retail-turned-wholesale stranded costs.[709] These commenters submit, among other things, that the Commission's jurisdiction over such costs is clear.[710] Coalition for Economic Competition states that when a utility's costs are stranded through the availability of Commission-jurisdictional transmission service, the Commission must address those costs. It argues that commenters opposing the Commission's jurisdiction fail to analyze the Commission's duty to establish just and reasonable rates for Commission-jurisdictional transmission service.

A number of commenters support the Commission's proposal to address retail-turned-wholesale stranded costs on the basis that many state commissions either lack authority to address costs that are stranded because of expanding or newly-created municipal systems, or have failed to address such costs.[711] El Paso adds that any protection offered by state judicial condemnation proceedings does not obviate the need for the Commission's involvement in this issue, noting that condemnation awards may not provide full stranded investment recovery under the Commission's standards. In addition, El Paso suggests that municipalization may occur through means other than condemnation of the distribution systems of electric utilities, such as when a municipality constructs its own, duplicative distribution facilities.

Several commenters also indicate that by forthrightly addressing this issue, the Commission has removed a cloud of uncertainty that would have taken years to resolve through litigation.[712] El Paso states that the proposed rule is needed because utilities may be subject to stranded costs resulting from municipalization in two separate state jurisdictions.

In response to the argument that stranded costs are exclusively subject to state jurisdiction, SoCal Edison asserts that whether the costs are retail or wholesale is irrelevant because the issue is how and where these costs should be recovered. According to SoCal Edison, if the Commission finds that these costs are just and reasonable costs associated with providing open access transmission service, the Commission may allow utilities to recover them in Commission-regulated rates.

Coalition for Economic Competition notes that while utilities are aware of state laws allowing municipalities to condemn electric facilities and to form utilities, in recent decades, it has not happened on most systems. Moreover, it argues that merely being on notice that municipalization is a possibility does not relieve utilities of their state-imposed obligation to serve all

[701] *E.g.,* American Iron & Steel, MD Com, LA DWP, Suffolk County, MI Com, NJ BPU, N.Y. Mayors. NASUCA cites practical problems posed by the Commission's proposal to assume jurisdiction over stranded costs resulting from municipalization, such as how the Commission would transfer the revenues extracted from the retail-turned-wholesale customer to a non-wholesale, locally-franchised entity.

[702] NARUC Initial Comments at 18–19.

[703] *E.g.,* N.Y. Mayors, NIEP, Wing Group, VT DPS, NY Industrials, American Iron & Steel, Environmental Action, IN Industrials, Las Cruces, Caparo, UT Industrials.

[704] *E.g.,* IN Com.

[705] *E.g.,* VT DPS, American Iron & Steel. American Forest & Paper states that allowing stranded cost recovery in the event of municipalization would be inconsistent with the Commission's actions in the natural gas industry, where the Commission has encouraged competition at the retail level (through competitive bypass rather than franchise competition) and has not imposed transition charges or exit fees on converting customers.

[706] VT DPS Initial Comments at 49; *see also* American Iron & Steel, NY Industrials, Caparo.

[707] 63 FERC ¶ 61,212 (1993), *reh'g denied,* 64 FERC ¶ 61,087 (1993).

[708] *See* Massachusetts Electric Company, 68 FERC ¶ 61,101 (1994); Letter Order dated March 3, 1995, Docket No. ER94–129–000 (approving settlement).

[709] *E.g.,* EEI, PSE&G, Centerior, Com Ed, Consumers Power, Detroit Edison, Duke, El Paso, Entergy, LILCO, Minnesota Power, Montana-Dakota Utilities, NYSEG, PECO, PG&E, PSNM, Southern, Utilities For Improved Transition, Allegheny, OH Com, Utilicorp, PA Com, WI Com, Coalition for Economic Competition, Central Louisiana, United Illuminating, Utility Investors Analysts, Nuclear Energy Institute, Utility Shareholders.

[710] *E.g.,* Consumers Power, Coalition for Economic Competition, Utilities For Improved Transition.

[711] *E.g.,* Detroit Edison, Minnesota Power, El Paso, LILCO, Centerior, PG&E. PG&E urges a clarification in the rule so that the Commission would address retail-turned-wholesale stranded costs only if the state commission either lacks jurisdiction over municipal utilities, or, if it has jurisdiction, declines to address stranded costs. Where a state commission possesses jurisdiction over municipal entities and provides a utility with stranded cost recovery from former retail customers that have municipalized, PG&E proposes that such action should be final and not subject to Commission review. Other commenters, such as El Paso, ask the Commission to establish itself as the forum of last resort when states do not provide for full recovery of stranded costs.

[712] E.g., Coalition for Economic Competition, El Paso.

customers in their franchise areas. It asserts that utilities had to continue to invest in plant to satisfy their duty to serve. In addition, it submits that utilities had a reasonable expectation that they would continue to serve retail load because, among other things, state regulators set long amortization periods of 30–40 years for depreciation rates.

Some commenters state that the Commission also should ensure that stranded costs are recovered when a municipal utility annexes territory served by another utility or otherwise expands its service territory.[713] A number of commenters also urge the Commission to ensure recovery of costs that are stranded if a municipal utility or a newly-formed wholesale or municipal utility physically interconnects to another utility or builds new transmission or distribution facilities to the municipal system.[714]

Several commenters believe that close coordination between the Commission and state regulators as to the calculation of stranded costs is important in the case of municipalization.[715] A number of state commissions suggest that the Commission allow the states to set the level of retail-turned-wholesale stranded costs to be recovered in wholesale transmission rates set by the Commission.[716] They submit that this approach would respect state interests in controlling the rate impact of stranded costs, while allowing the Commission to design cost recovery, and would address the needs of industrial customers and other stakeholders by providing a forum before state regulators who will be more aware of their particular needs. Further, they contend that this approach would prevent relitigation of issues, minimize forum-shopping, and prevent legitimate and verifiable costs from falling through the cracks or being double-recovered.[717] NY Industrials asks the Commission to clarify that utilities will not be allowed to seek cost recovery at both the Commission and state commissions.

Commission Conclusion

We reaffirm our preliminary determination that this Commission should be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. If such a customer is able to reach a new generation supplier because of the new open access (through the use of a FERC-filed open access transmission tariff or through transmission services ordered pursuant to section 211 of the FPA), we believe that any costs stranded as a result of this wholesale transmission access should be viewed as ''wholesale stranded costs.'' Such costs would not be stranded *but for* the action of this Commission (either through a mandatory FPA section 205–206 open access tariff or an order under FPA section 211) in permitting the new wholesale entity to become an unbundled transmission services customer of the utility and thereby to obtain power from a new supplier.[718] There is a clear nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs. In these circumstances, we believe that this Commission should be the primary forum for addressing recovery of such costs. To avoid forum-shopping and duplicative litigation of the issue, we expect parties to raise claims before this Commission in the first instance.[719]

Some commenters have asked us also to be the primary forum for stranded cost recovery in situations in which an existing municipal utility annexes territory served by another utility or otherwise expands its service territory. We decline to do so because in these situations there is no direct nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs. The risk of an existing municipal utility expanding its territory was a risk prior to the Energy Policy Act and prior to any open access requirement.

Nevertheless, we are concerned that there may be circumstances in which customers and/or utilities could attempt, through indirect use of open access transmission, to circumvent the ability of any regulatory commission—either this Commission or state commissions—to address recovery of stranded costs.[720] We reserve the right to address such situations on a case-by-case basis.

As we indicated in the Supplemental Stranded Cost NOPR, if the state has permitted any recovery from departing retail-turned-wholesale customers (for example, if it imposed an exit fee prior to, or as a condition of, creating the wholesale entity), that amount will not, in fact, be stranded, and we will deduct that amount from the legitimate stranded costs for which we will allow recovery.

As discussed in Sections IV.J.8–IV.J.9, we will require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer, and will apply the same procedures for determining stranded cost obligation, as that required in the case of a wholesale requirements customer.

[713] *E.g.*, EEI, Minnesota Power, Centerior, Public Service Co of CO, SoCal Edison, Coalition for Economic Competition. PG&E asks that we allow utilities to seek recovery at the Commission for stranded costs attributable to former retail customers that have become customers of existing public agencies or municipal utilities where such costs cannot be collected at the state level.

[714] *E.g.*, Centerior, Coalition for Economic Competition, PG&E. Coalition for Economic Competition proposes that the Commission accept just and reasonable regional stranded cost recovery mechanisms in such situations to enable regional transmission associations (whether through pool and interpool arrangements or regional transmission groups) to collect through Commission-filed rate schedules from interconnected utilities charges equal to the costs otherwise stranded as a result of Commission-jurisdictional service realignments.

[715] *E.g.*, SoCal Edison, OH Com, NY Com, MI Com, Coalition on Federal-State Issues.

[716] *E.g.*, MI Com, NY Com, Ohio Com.

[717] PG&E proposes a similar approach, noting that if there are differences in the stranded cost method used by the Commission and the states, an incentive may remain for retail customers to municipalize merely to take advantage of more favorable stranded cost treatment at the Commission.

[718] Costs that are exposed to nonrecovery when a retail customer or a newly-created wholesale power sales customer ceases to purchase power from the utility and does not use the utility's transmission system to reach a new generation supplier (*e.g.*, through self-generation or use of another utility's transmission system) do not meet the definition of ''wholesale stranded costs'' for which this rule provides an opportunity for recovery. Such costs are outside the scope of this rule because such costs would not be stranded as a result of the new open access. *See* Section IV.J.12.

[719] We recognize that we took a different approach to retail-turned-wholesale stranded cost recovery in *United Illuminating*, where we suggested that state and local regulatory authorities or the courts should be able to provide an adequate forum to address retail franchise matters, including recovery of stranded costs caused by municipalization, but said we would consider revisiting the question if United Illuminating could demonstrate the lack of a forum. 63 FERC at 62,583–84. Since the issuance of that decision, however, we have had an opportunity to re-analyze the nature of the stranded cost problem in cases where a retail customer becomes a wholesale customer, including the potential that there might not be a state regulatory forum for recovery of such costs. In these circumstances, we have determined that where such costs are stranded as a result of wholesale open access transmission, these costs should be viewed as wholesale stranded costs and this Commission should be the primary forum for addressing their recovery.

[720] The CA Com has asked that, ''(t)o the extent of FERC's authority, it should assume jurisdiction to fulfill a backstop role in case retail customers evade a state-determined transition charge by becoming retail customers of an entity not subject to the state regulatory commission's jurisdiction. In assuming jurisdiction, the Commission should defer to the state commission's determination and allocation of stranded costs for the departing retail customer.'' CA Com March 18, 1996 Response to Supplemental Comments of PG&E.

7. Recovery of Stranded Costs Caused by Retail Wheeling

In the Supplemental Stranded Cost NOPR, we stated that both this Commission and state commissions have the legal authority to address stranded costs that result from retail customers who obtain retail wheeling from public utilities in order to reach a different generation supplier.[721] Because the vast majority of commenters urged the Commission not to assume responsibility for retail stranded costs, except in certain circumstances, we preliminarily concluded that it is appropriate to leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. We proposed to entertain requests to recover stranded costs caused by retail wheeling only when the state regulatory authority does not have authority under state law to address stranded costs at the time when the retail wheeling is required.[722] In so doing, we preliminarily accepted the view that stranded costs caused by retail wheeling are primarily a matter of local or state concern and thus, with the limited exception discussed above, generally must be recovered through retail charges.

We noted that the states have a number of mechanisms for addressing stranded costs caused by retail wheeling, one of which is a surcharge to state-jurisdictional rates for local distribution.[723] We encouraged the states to use the mechanisms available to them to address stranded costs.[724] We also noted that the states may use their jurisdiction over local distribution facilities to address ''stranded benefits,'' such as environmental benefits associated with conservation, load management, and other demand side management programs.[725]

Comments

A number of commenters support the Commission's proposal for addressing stranded costs caused by retail wheeling.[726]

Other commenters urge the Commission to take a greater role in retail stranded cost recovery and to entertain requests to recover stranded costs as a backstop where: (1) State regulatory authorities have the authority to address stranded costs but either choose not to exercise that authority or fail to permit full stranded cost recovery;[727] or (2) the state commission's authority is unclear.[728]

Commenters that support a greater Commission backstop role argue, among other things, that because the Commission has exclusive ratemaking jurisdiction over any stranded cost charges imposed ''for or in connection with'' interstate transmission service by public utilities, the Commission has an obligation to regulate the recovery of stranded costs from interstate retail transmission customers.[729] A number of these commenters argue that the determining factor is who has the jurisdiction to review the rates for the service, not who has the jurisdiction to order the service.[730] They explain that the Commission has jurisdiction over generating facilities and associated costs to the extent appropriate to establish just and reasonable rates for jurisdictional services. They disagree with other commenters who argue that only the jurisdiction under whose authority the costs were incurred and initially recovered should have authority to order recovery of stranded costs.[731]

These commenters contend that the Commission cannot abdicate its regulatory responsibilities by either deferring to the state commissions or otherwise failing to independently address the issue.[732] EEI and the Coalition for Economic Competition refer to ''a long line of cases (where) the courts have held that where a federal regulatory agency * * * is charged with implementing a statutory framework, that agency is without authority to deviate from or abdicate its statutory responsibilities.''[733] According to Coalition for Economic Competition, for example, the Commission could satisfy its obligation to address stranded costs that arise from retail wheeling by allowing states to determine retail stranded cost charges in the first instance; to the extent that the state allows full recovery, Coalition for Economic Competition submits that the Commission's obligation would be satisfied.

EEI asserts that it would be unduly discriminatory and preferential for the Commission to refuse to address all stranded costs arising from retail wheeling. According to EEI, the same arguments that support the Commission's decision to address costs that are stranded where retail load municipalizes and where the state regulatory authority, at the time retail wheeling is required, lacks authority to act, apply with equal force to all other retail stranded costs. EEI submits that the nexus in these cases is that Commission-jurisdictional transmission service is the means by which the costs are stranded.[734]

Utility Working Group argues that the NOPR inappropriately characterizes the Commission's jurisdiction over retail stranded costs and that this could later be used against the Commission's exercise of its full authority. According to Utility Working Group, the NOPR depicts the Commission's jurisdiction as

[721] As discussed in Section IV.I, the Commission's authority to address retail stranded costs derives from its jurisdiction over the rates, terms and conditions of unbundled transmission in interstate commerce used by retail customers that obtain retail wheeling. The states' authority derives from state jurisdiction over local distribution facilities and over the service of delivering electric energy to end users, and from the authority to impose, among other things, retail exit fees and surcharges on local distribution rates.

[722] We proposed to require the same evidentiary demonstration for recovery of stranded costs from a retail customer that obtains retail wheeling as that required in the case of a wholesale requirements customer. We also reaffirmed our proposal in the initial Stranded Cost NOPR that a utility will have to show that the stranded costs are not more than the net revenues that the retail customer would have contributed to the utility had it remained a retail customer of the utility, and that the utility has taken and will take reasonable steps to mitigate stranded costs. FERC Stats. & Regs. ¶ 32,514 at 33,128.

[723] As we noted in the Supplemental NOPR, a state may require payment of an exit fee before a franchise customer is permitted to obtain unbundled retail wheeling. If local distribution facilities are used by a retail wheeling customer, the state may allow recovery of stranded costs through rates for use of such local distribution facilities. In addition, as discussed in Section IV.I, because we believe that states have authority over the *service* of delivering electric energy to end users, not merely the local distribution facilities themselves, state authorities can assign stranded costs and benefits through a local distribution service charge, and may do so based on usage (kWh), demand (kW), or any combination or method they find appropriate. If a state decides not to take any of these routes, it may consider whether to allow recovery of stranded costs from remaining retail customers or whether shareholders should bear all or part of those costs. *Id.* at 33,129.

[724] *Id.* at 33,129–30.

[725] *Id.* at 33,098 n. 230.

[726] *E.g.*, Utilicorp, Houston L&P, PG&E, Freedom Energy Co, WI Com.

[727] *E.g.*, EEI, EGA, Coalition for Economic Competition, Utilities for Improved Transition, Atlantic City, Arizona, Centerior, Com Ed, Detroit Edison, El Paso, LILCO, NU, NSP, NYSEG, United Illuminating, BG&E, Sierra, Southern, UT Industrials, NRECA. NRECA argues that unless the Commission addresses stranded costs caused by retail wheeling where a state commission lacks authority, or has authority but decides not to exercise it, there could be a jurisdictional gap into which many rural electric cooperatives could fall.

[728] *E.g.*, CSW.

[729] *E.g.*, EEI, Illinois Power, PSNM, Entergy, Nuclear Energy Institute, Coalition for Economic Competition.

[730] *E.g.*, Coalition for Economic Competition, Illinois Power, Utilities for Improved Transition, EEI.

[731] EEI notes, for example, that as use of electrical facilities shifts between retail and wholesale, jurisdiction over the rates to recover the allocated cost of service shifts between state commissions and this Commission, and that the regulatory authority is determined by the nature of the transactions and the classification of the customer, not the jurisdiction under which the costs originally arose.

[732] *E.g.*, Illinois Power, Utilities For Improved Transition, EEI, Coalition for Economic Competition.

[733] EEI Initial Comments at IV–13; *see also* Coalition for Economic Competition Initial Comments at 23–31.

[734] *See also* SoCal Edison.

being derived from state law (in other words, the Commission will act where state regulatory authorities have no authority over retail stranded costs and will not act where state regulatory authorities have such authority). If the Commission desires to afford substantial deference to the states regarding retail stranded costs, Utility Working Group contends that the final rule should reflect that policy determination; however, the rule should not confuse policy with jurisdiction by purporting to place limits on, or attempting to waive, the Commission's jurisdiction over such costs.

Entergy asserts that the Commission's jurisdiction over multi-state utilities provides further support for our jurisdiction over retail stranded costs in certain contexts. Entergy states that most of the eleven multi-state registered holding company systems have some form of Commission-jurisdictional agreement that allocates production and transmission costs among the systems' affiliated operating companies. It asserts that these agreements by their very nature allocate costs among jurisdictions (that is, between states). Many of these agreements equalize the cost of generating reserves among affiliated operating companies, and such reserve equalization formulas can shift retail stranded costs among states unless the Commission provides a regulatory forum to address cost-shifting. Citing *Middle South Energy*,[735] and *City of New Orleans* v. *FERC*,[736] Entergy submits that the Commission cannot sit on the sidelines when it comes to stranded retail costs on the Entergy system. According to Entergy, Commission and judicial precedent place on the Commission the responsibility to ensure that federally-approved costs and cost allocations are not undermined by state action.

Commenters also express concern that it will not be possible to be sure that a state regulatory authority has authority over retail stranded costs until after years of litigation. If the Commission waits for the resolution of challenges to state authority and a court holds that the state regulatory authority is without authority, these commenters assert that the bar on retroactive ratemaking could leave the states and the Commission without a remedy to compensate utilities for stranded costs.[737] A number of commenters suggest that while the states should be allowed to set retail wheeling stranded cost charges in the first instance, the Commission should accept filings to preserve a utility's ability to recover retail stranded costs from the time the customer departs if the state-authorized charges are not upheld in court. They submit that this would put customers on notice of the potential for Commission action and thereby avoid the retroactivity problem.[738]

Some commenters express concern that if the Commission does not take more decisive action on retail wheeling stranded costs, the result will be wasteful litigation that will discourage competition by causing financial uncertainty and higher financing costs for investor-owned utilities and higher rates for consumers.[739] Coalition for Economic Competition also asserts that stranded cost charges would be greatest at the start of a retail wheeling program, thereby making the years during which the state-authorized charges are subject to appeal more important for recovery purposes.

A number of commenters support Commission-established uniform standards for, and uniform recovery of, costs stranded as a result of open access to the interstate transmission system.[740] They argue that disparate state treatment of stranded costs would be economically inefficient and discriminatory and would burden interstate commerce.[741] Several commenters support state involvement in the establishment of uniform standards.[742]

In contrast to the commenters that support a greater Commission role in retail stranded cost recovery, NARUC and a number of other commenters oppose any Commission involvement in retail stranded costs.[743] These commenters contend, among other things, that the Commission lacks authority over these costs. Even if the Commission could assert such jurisdiction, they argue that as a policy matter it would be inappropriate for the Commission to delve into complicated legal and policy issues governed by varying state regulatory regimes.

According to some of these commenters,[744] section 201(a) of the FPA precludes an exercise of federal jurisdiction over retail stranded cost recovery because the Commission's jurisdiction extends ''only to those matters which are not subject to regulation by the States.'' [745] NM Industrials argues that a lack of state commission authority is an affirmative state determination, either by act or omission, that stranded costs must be dealt with in a particular manner. It submits that the Commission also lacks authority over retail stranded costs when states either decide not to address such costs or, in the Commission's opinion, grant insufficient recovery of stranded costs. NM Industrials asserts that the language of the FPA and its legislative history indicate that Congress wanted to preclude Commission jurisdiction in those areas where states could exercise effective control, and that this limitation covers all matters which are or can be regulated by the states, including the recovery of stranded investment. NM Industrials also suggests that assertion of Commission jurisdiction would violate the provision of section 212 of the FPA that prohibits the Commission from interfering with the states' authority over the transmission of energy directly to an ultimate consumer.[746]

Other commenters argue that the Commission's proposed treatment of retail stranded costs infringes on the states' jurisdiction over the allocation of costs that were under their jurisdiction when the costs were incurred. According to these commenters, the question of whether these costs should be recovered from other retail ratepayers, eliminated as excess capacity, or billed in some fashion to the customer now receiving wheeling service are purely questions of state ratemaking law.[747] Some commenters assert that, as a matter of policy, the Commission should stay out of retail stranded costs because only the states have sufficient knowledge and expertise regarding utility planning, investment,

[735] Opinion 234, 31 FERC ¶ 61,305, on reh'g, 32 FERC ¶ 61,425 (1985).

[736] 875 F.2d 903 (D.C. Cir. 1989), *cert. denied sub nom.* Mississippi v. FERC, 494 U.S. 1078 (1990).

[737] *E.g.*, NU, Coalition for Economic Competition, Illinois Power, EEI.

[738] *E.g.*, NEPCO, EEI, Coalition for Economic Competition, Entergy.

[739] *E.g.*, LILCO, Coalition for Economic Competition.

[740] *E.g.*, NU, NSP, Illinois Power, Coalition for Economic competition, PSE&G, Utilities For Improved Transition, Philip Morris, EEI.

[741] Freedom Energy Co. rejects this argument on the basis that state regulation has never been wholly consistent and yet utilities have not asked for federal unification of state ratemaking policies or resolution of differences.

[742] E.g., PSNM, GA Com, Omaha PPD, Illinois Power.

[743] *E.g.*, CA Com, MD Com, VA Com, IN Com, NH Com, NV Com, NY Com, OH Com, FL Com, AZ Com, TX Com, ELCON, NY Industrials, NY AG, NY Consumer Protection, MA DPU, Iowa Board, IN Industrials, Texas Industrials, NM Industrials, Reynolds, NYMEX, Legal Environmental Assistance, CO Consumers Counsel, NJ Ratepayer Advocate, IBM, ME Industrials, Jay, WEPCO, NH General Court.

[744] *E.g.*, NARUC, ELCON, NY Industrials, NM Industrials, NV Com.

[745] 16 U.S.C. 824(a).

[746] *See also* Freedom Energy Co. Reply Comments.

[747] *E.g.*, ELCON, PA Com, NY Industrials, ND Com, VA Com, NM Com.

and forecasting to address these costs adequately.[748]

Commenters also express concern that the possibility of Commission involvement in retail stranded cost recovery will encourage forum-shopping whenever state commission action is unfavorable, even when states have procedures to deal with stranded costs. They argue that the result would be endless litigation over where federal jurisdiction ends and where state jurisdiction begins. They suggest that if a state fails to address retail stranded cost recovery, the issue should be addressed in court or in state legislatures.[749] OH Com contends that a Commission policy that does not recognize states' authority over retail stranded costs would be a disincentive for states to permit retail wheeling.

A number of commenters argue that recovery of retail stranded costs is not directly implicated by any Commission or Congressional action—that most such costs would be created by retail wheeling, which is not the subject of the Commission's open access initiatives—and thus need not be dealt with as part of the final rule.[750]

Commenters seek a number of clarifications concerning the Commission's position on, and the procedures for, retail stranded cost recovery. A number of commenters ask the Commission to clarify the states' role with respect to retail stranded cost recovery.[751] Others address the type of evidence required to establish that the state regulatory authority lacks authority to address stranded costs when retail wheeling is required.[752]

Several commenters express concern that customers receiving retail wheeling not be able to evade state stranded cost charges.[753] IL Com says that the Commission's proposal for determining whether facilities are state-jurisdictional ''local distribution'' facilities or Commission-jurisdictional ''transmission'' facilities in interstate commerce may not always provide a state with the opportunity to recover retail stranded costs through distribution rate surcharges. It says that the Commission does not offer any assurances that the case-by-case application of the proposed ''functional-technical test'' will result in a finding that ''local distribution'' facilities are used in all retail wheeling scenarios. PG&E asks the Commission to provide that all retail customers that opt for direct transmission access by definition take service over local distribution facilities and therefore may be subjected to a state-determined distribution rate that includes stranded cost surcharges.

A number of commenters ask the Commission to clarify that, in issuing the final rule, the Commission is not endorsing (either implicitly or explicitly) retail wheeling.[754]

Several commenters express concern that stranded costs may arise in one state jurisdiction and be shifted to another.[755] For example, MT Com says that an analysis confined to a state's boundaries may reveal no stranded costs, but that such costs may indirectly arise because of common pool revenue recovery mechanisms, which may be the largest source of stranded costs for some utilities. Entergy raises a similar concern in the context of holding company or other multi-state situations. It argues that denial of retail stranded cost recovery by a state regulatory authority could harm customers in other states. Entergy proposes that, while state regulators should be given the opportunity in the first instance to assure that stranded costs are recovered and are not shifted to other states, the Commission should allow utilities to file retail wheeling tariffs with the Commission to preserve the right to seek recovery from the Commission.

Several commenters oppose Entergy's proposal.[756] Among other things, they argue that the FPA does not authorize the Commission to act as an appellate court over retail regulators. They assert that, in the case of a multi-state holding company system, it is the Commission-jurisdictional intra-system agreement (not a state's decision as to recovery of retail stranded costs) that determines the allocation of costs at wholesale among the affiliates. Several of these commenters suggest that if the holding company believes that, as a result of a state's disallowance of costs in retail rate base, the cost allocations under an intra-system agreement are unduly discriminatory, the holding company could propose to amend the agreement.[757]

A number of commenters also express concern that services that investor-owned utilities provide to promote energy efficiency and conservation and to assist low-income residents and the elderly be continued.[758] NW Conservation Act Coalition suggests that the Commission should condition stranded cost recovery upon a showing by the utility that allowing recovery will not strand such social benefits.[759]

Various commenters endorse the use by state regulators of a distribution charge or other fee imposed on electricity consumption to address stranded social benefits.[760] NARUC and OH Com express concern that the Commission, by claiming authority over unbundled retail transmission services, may make it difficult for states to use non-bypassable ''wires charges'' or ''access fees'' to require all customer classes to support such programs.[761] NARUC asks the Commission to ensure that any jurisdiction we exercise over unbundled transmission services does not legally or practically foreclose the ability of individual states to fund such programs.[762] LILCO, as part of its argument that the Commission should provide a complete backstop for stranded cost recovery resulting from retail wheeling, urges the Commission to establish retail wheeling rates that provide for full recovery of any stranded costs, including stranded social benefits,

[748] *E.g.*, OH Com, NY Industrials, NM Com, IN Com, WA Com, NV Com, NY Com, Suffolk County, NY AG, Tonko, PA Industrials, NH General Court.

[749] *E.g.*, OH Com, PA Com, NM Com, CA Com, Blue Ridge.

[750] *E.g.*, Nucor, AEC & SMEPA.

[751] *E.g.*, NY Industrials, EGA, NJ BPU, Coalition on Federal-State Issues.

[752] *E.g.*, Iowa Board, Nevada Commission, CCEM; *see also* NE Public Power District.

[753] *E.g.*, IL Com, PG&E, Public Service Co of CO.

[754] *E.g.*, NRECA, Wisconsin EC, EEI, PECO, Missouri Basin Group.

[755] *E.g.*, MT Com, Entergy.

[756] *E.g.*, NARUC, Entergy Retail Regulators, MS Com, Al Com.

[757] *E.g.*, NARUC, MS Com.

[758] *E.g.*, Homelessness Alliance, Black Mayors, National Women's Caucus, Vann, La Raza.

[759] NARUC and OH Com assert that, in determining whether a wholesale transmission transaction is a ''sham,'' the Commission should consider a retail customer's intent to bypass responsibility for supporting social programs.

[760] *E.g.*, Natural Resources Defense, NW Conservation Act Coalition, Seattle, FTC, Northeast States for Coordinated Air Use Management, NARUC, OH Com. CO Com agrees that states should have the option to fund such programs through the imposition of surcharges on any form of electric service used to benefit retail customers, including surcharges on retail transmission rates. Seattle proposes either a simple fee on kWhs or a differential fee based on the type of resource and its environmental affects. DOE urges the Commission to work with state regulators to ensure that states have the ability to recover stranded retail costs and benefits in a way that prevents cost-shifting, forum-shopping, and uneconomic bypass (including bypass of stranded benefits).

[761] CO Com notes that the NOPR proposes to limit states to funding mechanisms that can be implemented solely at the local distribution level, presumably through the use of a surcharge on distribution facilities or so-called ''fee at the meter'' or the use of a local distribution system revenue decoupling mechanism. It suggests that neither of these options may be legally or practically feasible in many states for a wide variety of reasons (but does not expand on these reasons).

[762] Natural Resources Defense proposes that the Commission adopt the following language: ''The FPA does not affect state regulators' jurisdiction to apply distribution charges—either volume-based or fixed—to electricity that is used by any utility customer to provide end-use services (as distinguished from electricity that is purchased for resale to end-use customers).'' Natural Resources Defense Initial Comments at 3.

that are unrecovered after state stranded cost determinations.

Commission Conclusion

We believe that both this Commission and the states have the legal authority to address stranded costs that result when retail customers obtain retail wheeling in order to reach a different generation supplier, and that utilities are entitled, from both a legal and a policy perspective, to an opportunity to recover all of their prudently incurred costs. This Commission's authority to address retail stranded costs is based on our jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce. The authority of state commissions to address retail stranded costs is based on their jurisdiction over local distribution facilities and the service of delivering electric energy to end users. However, because it is a state decision to permit or require the retail wheeling that causes retail stranded costs to occur, we will leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. The only circumstance in which we will entertain requests to recover stranded costs caused by retail wheeling is when the state regulatory authority [763] does not have authority under state law to address stranded costs when the retail wheeling is required.

Commenters that describe our action as an unlawful abdication or delegation of authority misconstrue the nature of our decision to leave retail stranded costs (with a limited exception) to state regulatory authorities.[764] We have not ''abdicated'' or ''delegated'' to state regulatory authorities our jurisdiction over the rates, terms, and conditions of retail transmission in interstate commerce; if retail transmission in interstate commerce by a public utility occurs, public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205. Instead, we have made a policy determination that the recovery of retail stranded costs—an issue over which either this Commission or state commissions could exercise authority by virtue of their jurisdiction over retail transmission in interstate commerce and over local distribution facilities and services, respectively—is primarily a matter of local or state concern that should be left with the state commissions. However, if the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required, then we will entertain requests to recover such costs.[765]

Because we have accepted the view that stranded costs caused by retail wheeling are primarily a matter of local or state concern, we will not allow the states to use the interstate transmission grid as a vehicle for passing through any retail stranded costs, with the following limited exception. If the state regulatory authority does not have authority under state law when the retail wheeling is required to resolve the retail stranded cost issue, we will permit a utility to seek a customer-specific surcharge to be added to an unbundled transmission rate.

We believe that most states have a number of mechanisms for addressing stranded costs caused by retail wheeling.[766] In addition, as further discussed in Section IV.I, we are defining in this rule ''facilities used in local distribution'' under section 201(b)(1) of the FPA. Rates for services using such facilities to make a retail sale are state-jurisdictional, and states will be free to impose stranded costs caused by retail wheeling on facilities or services used in local distribution. States may also use their jurisdiction over local distribution facilities or services to recover so-called stranded benefits. This rule is not intended to preempt any existing state authority to assess a stranded cost or stranded benefits charge on a retail customer that obtains retail wheeling. Moreover, since the charge is state jurisdictional, it is of no moment to our responsibilities under the FPA as to whether such charges are volume-based (kWh), demand-based (kW), or customer-based (fixed).

We believe that our approach to retail wheeling stranded costs represents an appropriate balance between federal and state interests. This approach ensures that the rates for transmission in interstate commerce by public utilities (except in a narrow circumstance) will not be burdened by retail costs. It also helps to ensure that one state will not be able to impose costs stranded by its ordering of retail wheeling [767] on customers in another state.[768] In a holding company or other multi-state situation, we recognize that denial of retail stranded cost recovery by a state regulatory authority could, through operation of the reserve equalization formula in a Commission-jurisdictional intra-system agreement, inappropriately shift the disallowed costs to affiliated operating companies in other states. The Commission is concerned about this potential for cost-shifting. We would not wish to see an intra-system agreement used as a means for one jurisdiction to shift to other jurisdictions retail stranded costs for which it would otherwise be responsible under that agreement. However, we will deal with such situations if they arise pursuant to public utility filings under section 205 or complaints under section 206. Thus, the need to amend a jurisdictional agreement to prevent retail stranded costs from being shifted to customers in other states will be addressed on a case-by-case basis. We encourage the affected state commissions in such situations to seek a mutually agreeable approach to this potential problem. If such a consensus solution resulted in a filing to modify a jurisdictional agreement, we would accord such a proposal deference, particularly if other interested parties support the filing. In the event that the state commissions and

[763] ''State regulatory authority'' has the same meaning as provided in section 3(21) of the FPA.

[764] We reject the arguments of EEI and Coalition for Economic Competition that the Commission made findings in the initial stranded cost NOPR that ''inexorably'' lead to the conclusion that Commission action providing full recovery of retail stranded costs is required. Their reliance on *Williams Natural Gas Company* v. *FERC,* 872 F.2d 438 (D.C. Cir. 1989), *appeal after remand,* 943 F.2d 1320 (D.C. Cir. 1991) (*Williams*), is simply misplaced. *Williams* involved a rulemaking that was terminated by the Commission. The court stated that the Commission, ''having expressed these tentative views (that the incentive price for tight formation gas would disserve the public interest) and having solicited comments on the issue, was not free to terminate the rulemaking'' without providing a satisfactory explanation. 872 F.2d at 446, 450. Here, in contrast, we are issuing a Final Rule that reaffirms in many respects preliminary findings proposed in both the initial and Supplemental Stranded Cost NOPRs. Although the conclusion we reach based on those findings may be different than that which some commenters advocate, we have fully explained the basis for our decision.

[765] In these circumstances, the cases cited by commenters to support the proposition that an agency is not authorized to abdicate its statutory responsibilities or to delegate to parties and intervenors regulatory responsibilities (such as preparation of an environmental impact statement) are factually distinguishable and inapposite. *See, e.g.,* FPC v. Texaco, 417 U.S. 380, 394 (1974) (Commission cannot exempt small-producer rates from compliance with just and reasonable standard); United States v. City of Detroit, 720 F.2d 443, 451 (6th Cir. 1983) (district court inappropriately implied waiver of EPA statutory duty under Title II of the Federal Water Pollution Prevention and Control Act); State of Idaho v. ICC, 35 F.3d 585, 595–96 (D.C. Cir. 1994) (an agency cannot abdicate its NEPA responsibilities in favor of the regulated party).

[766] As discussed in the Supplemental NOPR (FERC Stats. & Regs. ¶ 32,514 at 33,129–30), these mechanisms include requiring an exit fee before a franchise customer is permitted to obtain unbundled retail wheeling and imposing a surcharge on local distribution rates. Commenters identified several other possible mechanisms in response to the initial Stranded Cost NOPR.

[767] As we stated in the Supplemental NOPR, we do not address whether states have the lawful authority to order retail wheeling in interstate commerce. *Id.* at 33,098 at n.228. In addition, we are neither endorsing nor discouraging retail wheeling.

[768] *See id.* at 33,098, 33,127–28.

other interested parties cannot reach consensus that would prevent cost shifting, the Commission would ultimately have to resolve the appropriate treatment of such stranded costs.

Should a situation arise in which a state regulatory authority concludes that it has no ability to address retail stranded costs, or the appropriate state courts ultimately determine that a state regulatory authority does not have authority to impose retail stranded costs, a utility may seek recovery here through its Commission-jurisdictional retail transmission rates of costs stranded as of the date of the customer's departure. Because all parties are put on notice by this Rule of the potential for recovery through Commission-jurisdictional retail transmission rates should state commission-authorized retail wheeling charges be invalidated, such recovery (if allowed) would not be retroactive ratemaking.[769]

8. Evidentiary Demonstration Necessary—Reasonable Expectation Standard

In the Supplemental Stranded Cost NOPR, the Commission made a preliminary determination that a public utility or transmitting utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. We indicated that the existence of a notice of termination provision in a wholesale requirements contract creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the period provided for in the notice provision.[770] We proposed not to adopt a minimum notice period for purposes of applying the rebuttable presumption. This was because whether a utility has a reasonable expectation of continuing to serve a customer, and for how long, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provision in the contract, will depend on the facts of each case.

We sought further comment concerning whether the reasonable expectation standard should apply if a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and where, in order to make such a sale possible, transmission service has been rendered by an intervening utility. We asked whether the Commission should take this as conclusive evidence that the customer had a choice of wholesale suppliers and, therefore, that the seller had no reasonable expectation that the contract would be extended. We further asked should we choose to provide the seller with an opportunity to prove that it had a reasonable expectation, what weight should be given to the fact that transmission service was rendered by the intervening utility. If the seller establishes that it had a reasonable expectation, and the former wholesale customer does not take unbundled transmission service from the former seller, we asked what if any means ought to be available for the collection of stranded costs.[771]

We also proposed to require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer or a retail customer that obtains retail wheeling as that required when a wholesale requirements customer leaves a utility's system. We proposed that the utility must demonstrate that it incurred stranded costs based on a reasonable expectation that the customer would continue to receive bundled retail services. We anticipated that the reasonable expectation test would be easily met in those instances in which state law awards exclusive service territories and imposes a mandatory obligation to serve. We requested comments on these proposals.[772]

Comments

a. Rebuttable Presumption

Some commenters oppose treating a notice provision as a rebuttable presumption that the utility had no reasonable expectation of continuing to serve a customer. Commenters representing the financial community (Utility Shareholders and Utility Investors Analysts), for example, state that investment in generation and other costs incurred in providing utility service have not been tied to notice provisions. Based on the use of notice provisions in the past, and their infrequent use for termination, they state that the financial community has not viewed notice provisions as a determinant of the financial basis of investment in the industry.

Other commenters also argue that the Commission interprets the intent behind termination notice provisions too narrowly. These commenters submit that the Commission should examine on a case-by-case basis whether a notice provision demonstrates a sufficient meeting of the minds between the parties that there was no reasonable expectation that the contract would be extended.[773] TVA notes that the existence of a notice provision in its contracts in no way implies that continued service would not be expected.

A number of commenters[774] note that some utilities have ''evergreen'' contracts that remain in effect indefinitely unless either party gives notice that it intends to terminate the contract. They argue that, with no date certain for termination, the provider of bundled service must proceed on the assumption that it will have to meet its contract obligations on a continued basis. CSW recommends that the Commission limit the rebuttable presumption standard to contracts that contain a fixed contract termination date. IN Com suggests that where a contract contains an evergreen provision, the Commission should consider how often the contract has been automatically renewed and the length of the notice period.

A number of commenters suggest that the following factors should be conclusive proof of a reasonable expectation (or sufficient to conclusively rebut the presumption of no reasonable expectation): (1) An obligation under statute, certificate of public convenience and necessity, order or otherwise, granted to the utility to provide service to the area that includes the customer; (2) participation by the customer in regulatory proceedings that defer the utility's complete recovery of the costs associated with existing investment to a later period; or (3) service under a wholesale rate that averaged the cost of all of a utility's generation resources, both long-term and short-term.[775] Utilities For Improved Transition maintains that a customer whose rates were based on the totality of a utility's resources, including those with long life expectancies,

[769] *See* Public Utilities Commission of the *State of California* v. *FERC*, 988 F.2d 154, 163–66 (D.C. Cir. 1993).

[770] FERC Stats. & Regs. ¶ 32,514 at 33,117.

[771] *Id.* at 33,118.

[772] *Id.* at 33,128.

[773] *E.g.*, Carolina P&L, CSW, Duke, Utilities for Improved Transition, Montaup, TVA, MidAmerican. MidAmerican states that, for years, utilities have entered into wholesale contracts containing termination notice provisions and, for years, customers have renewed and renegotiated those contracts. Duke agrees that more important indications of the utility's reasonable expectation of continuing to serve the customer can be found where the service has been included in the IRP process or the contract has been repeatedly renewed. Orange & Rockland proposes that there be a rebuttable presumption of recovery for long-standing (at least 10 years) contracts between utility affiliates on the basis that the existence of a long-standing relationship is of greater significance than a notice provision.

[774] *E.g.*, CSW, IN Com.

[775] *E.g.*, El Paso, Utilities For Improved Transition.

cannot claim that the governing expectation was that the utility would serve the customer only for a period of one to three years.

Other commenters, in contrast, assert that the rebuttable presumption does not go far enough. These commenters submit that a notice of termination provision should create a conclusive presumption that a utility had no reasonable expectation of continuing to serve a customer beyond the notice period.[776] Some commenters [777] also support a conclusive presumption of no reasonable expectation where one or more of the following grounds are present: (1) An explicit termination provision, regardless of the length of the pre-termination notice period; (2) an explicit provision for decreasing service or switching to partial requirements service; (3) a pre-existing transmission tariff or transmission service schedule; (4) NRC license conditions providing for transmission service or pooling rights; [778] (5) a municipal joint action agency or G&T cooperative with authority to supply the wholesale load in question; (6) a fixed-term contract; (7) membership in a power pool that provides access to regional markets; (8) a contract entered into after passage of the Energy Policy Act; or (9) other evidence of an ability to seek alternative suppliers. Several of these commenters, such as TAPS and Detroit Edison Customers, submit that a conclusive, irrebuttable presumption would decrease the number of disputes over stranded cost issues.

Several comments were submitted concerning the examples listed in the NOPR that the Commission suggested, depending on all of the facts and circumstances, could establish a reasonable expectation that a contract would be extended. These examples include lack of access to alternative suppliers, repeated contract renewals, failure of a customer to object to the imposition of construction-work-in-progress, or communications between supplier and customer concerning including the customer's load in system planning.[779] Some commenters argue that evidence of this type should not be enough to rebut the presumption (or to overcome a summary judgment motion based on the presumption) of no reasonable expectation for contracts with notice provisions.[780] ELCON objects to using a customer's lack of alternative supply as evidence of a continued service obligation; it submits that the historic lack of supply alternatives has been caused by undue exercise of market power and should not be rewarded.[781] Las Cruces suggests that if lack of opposition to construction-work-in-progress evidences a reasonable expectation of continued service, continuous opposition should evidence a reasonable expectation that the customer will depart a system at the earliest possible date. With regard to the Commission's suggestion that communications with the customer on the customer's future plans could establish reasonable expectation, Direct Service Industries submits that no claimed reliance should be deemed reasonable unless the seller obtained express assurances from the customer that the customer intended to continue to purchase power from the seller beyond its current contract.

We also received comments on the time at which the reasonable expectation had to exist. TAPS urges that the Commission should focus on whether a utility had a reasonable expectation of continued service when it entered into the most recent execution, renewal or amendment of the power supply contract.[782] PSE&G, on the other hand, argues that the focus of the Commission's review should be whether, at the time of incurring or obligating itself to incur the cost of serving a customer, the utility had a reasonable expectation of serving that customer for its planning horizon.

b. Application of Reasonable Expectation Standard to Non-Contiguous Service Territory

Some commenters discuss the situation in which a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and, in order to make such a sale possible, transmission service has been rendered by an intervening utility. They argue that this situation presents conclusive evidence that the customer had a choice of wholesale suppliers and, therefore, that the seller had no reasonable expectation that the contract would be extended.[783] Direct Service Industries submits that if a customer has power supply options that do not rely on access to the selling utility's transmission system, the selling utility could have had no reasonable expectations other than those expressly created by contract. NM Industrials submits that allowing recovery of stranded costs in this situation would also constitute retroactive ratemaking in violation of *Arkansas Louisiana Gas Company* v. *Hall*.[784] It argues that by assessing stranded costs at the close of a contract's term against customers that do not even need a generating utility's transmission services to leave its system, the Commission would retroactively alter the terms and conditions of the rates for generation negotiated between the parties and approved by the Commission.

Other commenters submit that in these circumstances the Commission should give the supplier the opportunity to prove that it had a reasonable expectation that it would continue to serve the customer.[785] ELCON and WP&L state that the reasonable expectation standard should be satisfied (or not) by reference to the parties' existing contract, regardless of whether the customer is in a contiguous service territory.

Utility Investors Analysts asserts that a seller will always have a reasonable expectation that a business relationship can be continued with a current customer and that the better presumption would be that the contract will be extended unless evidence to the contrary exists.

[776] *See, e.g.*, ELCON, NRECA, APPA, American Forest & Paper, Central Montana EC, Municipal Energy Agency Nebraska, Arkansas Cities, Direct Service Industries, Atlantic City, TDU Systems, Fertilizer Institute, LG&E, ABATE, Oglethorpe.

[777] *E.g.*, TAPS, Missouri Joint Commission, Detroit Edison Customers, LEPA, APPA, Cleveland.

[778] According to LEPA, the normal set of NRC license conditions included an explicit wheeling commitment and many of the license conditions clearly referenced the possibility that the wheeling commitment would lead to the loss of customers to whom the utility had been selling bulk power supply as well as retail power. LEPA submits that acceptance of such license conditions should have ended any reasonable expectation that a utility might have had of continuing to serve a full requirements customer, wholesale or retail, after the termination of its contract.

[779] *See* FERC Stats. & Regs. ¶ 32,514 at 33,117.

[780] *E.g.*, TAPS, Phelps Dodge. Phelps Dodge suggests that evidence of past contract renewals, by itself, should not serve to rebut the presumption that the utility has no reasonable expectation of contract renewal in the future.

[781] In contrast, EEI believes that lack of access to alternative suppliers can be evidence that a utility reasonably expected to continue to serve a customer.

[782] If the investment now alleged to be stranded was incurred after the most recent amendment or extension to the contract, TAPS would focus the reasonable expectation review on such later date.

[783] *E.g.*, IL Com, Utilicorp, PSG&E, NM Industrials.

[784] 453 U.S. 571 (1981).

[785] E.g., Florida Power Corp, Consumers Power, FL Com, TDU Systems.

c. Application of Reasonable Expectation Standard to Retail-Turned-Wholesale Customers or To Retail Wheeling

A number of commenters support the Commission's proposal to apply the reasonable expectation standard in these cases.[786] PA Com submits that the case-by-case analysis contemplated by the Commission for establishing a utility's reasonable expectation of continuing to serve a wholesale requirements customer should also apply in the case of a retail-turned-wholesale customer or a retail customer that obtains retail wheeling.

Some commenters believe that the reasonable expectation test would be easily met in those instances in which state law awards exclusive service territories and imposes an obligation to serve.[787] Some contend that the reasonable expectation standard should be presumed met in these circumstances because state law obligates a utility to serve all retail customers. A number of commenters assert that such a presumption would obviate the need for case-by-case showings concerning the expectations of each utility and the nature of each franchise.[788] At a minimum, several commenters propose that the Commission adopt a rebuttable presumption that utilities had an obligation to serve retail customers and therefore that the reasonable expectation test is met in a retail-turned-wholesale customer scenario or in the case of costs stranded as a result of retail wheeling.[789]

On the other hand, a number of commenters argue that there is no basis for a utility to reasonably expect that it will continue to serve a particular customer in states where franchises are non-exclusive.[790] Several of these commenters argue that a utility operating under a non-exclusive franchise is faced with the ever-present prospect that the communities it serves may build their own systems.[791]

Other commenters oppose the suggestion that the reasonable expectation test cannot be met where a franchise is non-exclusive or has terminated.[792] They argue that a utility's obligation to serve retail customers arises under state laws independent of the franchise. SoCal Edison explains that in states such as California, a franchise is nothing more than the source of a utility's right to use the city's streets, poles, rights of way, etc., and that a utility's duty to serve extends to all customers within its certificated service territories and not simply to those areas in which it has a franchise.

Commission Conclusion

We reaffirm that a utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. Whether a utility had a reasonable expectation of continuing to serve a customer, and for how long, will be determined on a case-by-case basis, and will depend on all of the facts and circumstances.[793]

Further, we will apply the reasonable expectation standard in those cases where a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and, in order to make such a sale possible, transmission service has been rendered by an intervening utility. We believe it is appropriate to give the utility an opportunity to prove that it had a reasonable expectation of contract renewal in circumstances in which the remote customer becomes an unbundled transmission services customer of the former supplier.[794]

We also reaffirm our determination that the existence of a notice provision in a contract creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the specified period. Whether or not a contract contains an ''evergreen'' or other automatic renewal provision will be a factor to be considered in determining whether the presumption of no reasonable expectation is rebutted in a particular case.

We will not adopt a minimum notice period for purposes of applying the reasonable expectation rebuttable presumption. Whether a utility had a reasonable expectation of continuing to serve a customer, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provisions in a contract, will depend on the facts of each case.

In addition, we reaffirm our preliminary determination to apply the reasonable expectation standard to retail-turned-wholesale customers. In this scenario, before the Commission will permit a utility to recover stranded costs, the utility must demonstrate that it incurred such costs based on a reasonable expectation that the retail-turned-wholesale customer would continue to receive bundled retail service. Whether the state law awards exclusive service territories and imposes a mandatory obligation to serve would be among the factors to be considered in determining whether the reasonable expectation test is met in a particular case.[795]

We further note that we are not addressing in this Rule who will bear the stranded costs caused by a departing generation customer if the Commission finds that the utility had no reasonable expectation of continuing to serve that

[786] *E.g.,* PA Com, Com Ed, CSW, United Illuminating, UFIT, PSNM, TDU Systems.

[787] *E.g.,* Com Ed, Central and Southwest, United Illuminating, Utilities For Improved Transition, Utility Investors Analysts, Utility Shareholders.

[788] E.g., EEI, Minnesota Power, PECO, Puget, Centerior, Florida Power Corp, FL Com, Southern, SoCal Edison, NEPCO, Consumers Power, Coalition for Economic Competition. NEPCO asserts that the Supplemental Stranded Cost NOPR does not cite any comments or evidence casting doubt on the Commission's initial proposal (in the initial Stranded Cost NOPR) not to apply the reasonable expectation test to retail-turned-wholesale or retail customers that obtain retail wheeling on the basis that utilities operating under an obligation to serve at retail necessarily have an entitlement to recover the costs prudently incurred in fulfillment of that obligation.

[789] *E.g.,* EEI, Detroit Edison, Centerior, Consumers Power, Ohio Edison.

[790] *E.g.,* Wing Group, Alma, Total Petroleum, Cleveland, ABATE, N.Y. Mayors, CAMU, Suffolk County.

[791] *E.g.,* Wing Group, Total Petroleum, ABATE, CAMU, NY Mayors. Proposals advanced by commenters to address non-exclusive franchises include suggestions that the Commission: summarily reject claims to recover retail stranded costs where the utility has a non-exclusive franchise and historically has been subject to retail competition (*e.g.,* Cleveland); apply a rebuttable presumption that a utility had no reasonable expectation of continued service where a municipal franchise is expiring and the municipality has put the retail supplier on notice that the municipality may seek an alternative source of power supply (*e.g.,* Las Cruces); or provide that no stranded cost claim will be entertained absent a showing, by reference to applicable state law, that the utility had an exclusive service franchise obligation or was otherwise subject to an obligation to serve the customer that is departing its system (*e.g.,* Phelps Dodge).

[792] *E.g.,* Utility Working Group, SoCal Edison, Florida Power Corp, PG&E. Referring to the Commission's statement that it expects the reasonable expectation test to be easily met in those instances in which state law awards exclusive territories *and* imposes a mandatory obligation to serve, Utility Working Group asks the Commission to make clear in the final rule that it did not intend by that example that utilities with non-exclusive service territories would be presumed to fail the reasonable expectation test. According to Utility Working Group, the focus of the test must be on the utility's obligation to serve, which may be separate from any franchise arrangements.

[793] The examples that the Commission provided in the Supplemental NOPR of possible ways to establish reasonable expectation were not intended to be dispositive of the issue. As we make clear in this Rule, whether a particular utility had a reasonable expectation that a contract would be extended will depend on all of the facts and circumstances.

[794] However, if the remote customer does not use the former supplying utility's open access tariff to reach the new supplier, there would be no ''wholesale stranded costs'' as that term is defined in this Rule. In this situation, we would not allow extra-contractual recovery of stranded costs. Thus, there would be no need to address reasonable expectation. *See* Section IV.J.12.

[795] The same procedures would apply to retail customers that obtain retail wheeling.

customer. As we suggested in the initial Stranded Cost NOPR,[796] we anticipate that, in such a case, a public utility will seek in subsequent requirements rate cases to have the costs reallocated among the remaining customers on its system. However, we will not prejudge that issue here.

9. Calculation of Recoverable Stranded Costs

In the Supplemental Stranded Cost NOPR, the Commission proposed that the determination of recoverable stranded costs be based on a ''revenues lost'' approach. Under this approach, stranded costs are calculated by subtracting the competitive market value of the power the customer would have purchased from the revenues that the customer would have paid had it stayed on the utility's generation system. We cited several benefits that we believe a ''revenues lost'' approach offers over a hypothetical cost-of-service approach, including avoidance of an asset-by-asset review, minimization of cost allocation procedures, and ease of application.[797]

We sought comments on how to calculate what the utility's revenue stream would have been had the customer continued service. We also sought comments on how to calculate the revenues that the utility would receive in a competitive market for the stranded assets. This included whether we should require the utility to track the actual selling price of the power over time or require the utility to use an up-front approach (such as an estimate of the forecasted market value of the power for the period during which the customer would have taken service). We asked whether we should allow prices in futures markets or forward markets to be used in an up-front approach, assuming such financial instruments become available.[798]

We suggested that the revenues lost approach automatically takes account of mitigation measures because it reduces the amount of stranded costs recoverable by a utility by the market price of the power that the customer no longer takes. We noted that this is particularly so if mitigation is reflected through a one-time, up-front estimate of the future market value of the power and is not trued up over time. We sought comments regarding implementation of a mitigation requirement. If mitigation is trued up over time, we asked how the Commission should ensure that the utility takes all reasonable steps to mitigate its own costs so as to minimize what the customer would have paid. We also asked how the Commission should ensure that the utility does its best to sell the power at its highest possible value. In addition, we asked whether there are other mitigation measures that should be taken into account (such as efficiency improvements that a utility would have undertaken regardless of whether the particular customer continued to take power under its contract, or cost savings resulting from the buy-out of a fuel contract made possible by the customer's departure).[799]

With regard to determining how long a utility could have reasonably expected to keep a generation customer (which we will call the ''reasonable expectation period''), we preliminarily found that a one-size-fits-all approach is not appropriate. We sought further comment with respect to whether the Commission ought to establish presumptions or, in the alternative, absolute limits on a customer's maximum liability when a utility establishes that it had a reasonable expectation that the contract would be extended. We inquired whether it would be appropriate to pick an outer limit equal to the revenues that the utility would lose during the length of one additional contract extension period, or during the length of the utility's planning horizon. We also asked what other events or criteria might be used to establish either presumptions or absolute limits on the reasonable expectation period.[800]

In addition, we proposed procedures for providing a customer advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[801] We invited comments on these procedures.[802]

Comments

a. Revenues Lost Approach

Numerous commenters, including almost all investor-owned utility commenters, support the revenues lost approach for calculating stranded costs.[803] Among other things, commenters maintain that the revenues lost approach is fair, reliable, and less complicated than the asset-by-asset approach. As discussed below, while some of these commenters support an ''up-front'' determination of stranded costs with no subsequent adjustments, others prefer use of a true-up mechanism whereby a customer's responsibility for stranded costs is adjusted to the extent that the actual competitive market value is different from the estimated market value used to determine the customer's up-front stranded cost charge.

Other commenters, on the other hand, oppose the revenues lost approach.[804] Some commenters state that the revenues lost approach provides no incentive to mitigate stranded costs because, by permitting a utility to recoup from a departing generation customer the difference between the contract price and a power resale price, the utility receives the same total revenues regardless of whether the customer stays or leaves and regardless of whether the utility effectively mitigates stranded costs.[805] Others maintain that the revenues lost approach is imprecise.[806] Referencing the problems associated with avoided cost projections used in setting QF rates under PURPA, some of these commenters submit that the revenues lost approach also requires significant assumptions (regarding projected revenue streams, service levels, and generic market value forecasts).[807] Among the other criticisms of the revenues lost approach that are raised by commenters are that it leads to over-recovery of stranded costs,[808] is

[796] FERC Stats. & Regs. ¶ 32,507 at 32,872.

[797] *Id.* at 33,121.

[798] *Id.*

[799] *Id.* at 33,123. We also asked how revenues received as a result of mitigation measures should be reflected in the determination of the amount of recoverable stranded costs; what special accounts, if any, should be created to track revenue liability for specific customers, revenues from mitigation measures, and other revenues received by the utility that offset the stranded cost liability; whether any adjustment should be permitted to the revenues that the utility claims will be realized in a competitive market for its stranded assets, and if so, how often and under what circumstances. Further, we sought comments on whether there are special costs that warrant some special consideration in the determination of stranded cost liability under a revenues lost approach, and if so, how they should be treated. *Id.* at 33,121–22.

[800] *Id.* at 33,122.

[801] *Id.* at 33,114–15.

[802] *Id.* at 33,115.

[803] *E.g.*, Centerior, NYSEG, Florida Power Corp, Houston L&P, NIMO, Orange & Rockland, Com Ed, PSE&G, EEI, PECO, Texas Utilities, PG&E, SoCal Edison, Dayton P&L, El Paso, IL Com, United Illuminating, Nuclear Energy Institute.

[804] *E.g.*, LG&E, TAPS, TDU Systems, ABATE, Blue Ridge, NY Energy Buyers, WP&L, PA Com, KY Com, American National Power, ELCON, Texaco, UT Com, NARUC, NIEP, DE Muni, Reynolds, Knoxville, Alma, APPA, NY Industrials, IL Industrials, SC Public Service Authority, Caparo, American Forest & Paper.

[805] *E.g.*, NIEP, DE Muni and TDU Systems.

[806] *E.g.*, SC Public Service Authority, ABATE, NY Energy Buyers, NARUC, ELCON, American Forest and Paper, APPA.

[807] *E.g.*, NARUC, NYSEG.

[808] *E.g.*, NRECA, NIEP, TDU Systems.

anticompetitive,[809] and that it leads to cost shifting.[810] NARUC and TDU Systems also maintain that it is likely that assets stranded by a customer's departure from the utility's generation system will be used to serve new customers but that the revenues lost approach offers no method of accounting for such ''unstranding'' of assets.

A number of commenters request clarification of the stranded cost formula contained in the NOPR, including specific instructions regarding how to calculate the revenues the customer would have paid the utility had it remained a customer and the competitive market value of the power the customer would have purchased.[811] Some of these commenters suggest that the stranded cost issue will be more contentious if the final rule does not provide greater detail.[812] Several commenters request that the Commission issue a detailed list of recoverable costs.[813] A number of commenters propose detailed alternatives to, or variations of, the revenues lost approach.[814]

Numerous commenters urge the Commission to be flexible and not overly prescriptive regarding the calculation of the formula components.[815] These commenters generally recommend that the Commission judge each stranded cost proposal on a case-by-case basis.[816]

Definition and Calculation of Revenue Stream

Some commenters maintain that the revenue stream component should be calculated based on the present rates paid by the customer.[817] These commenters state that because present rates have been approved by various commissions, the costs have been shown to be legitimate, prudent, and verifiable.

Other commenters oppose the use of current rates to calculate the utility's revenue stream. WP&L believes that the use of current rates would be overly generous and recommends capping the revenue measure at a regional average rate rather than a utility-specific rate. A number of other commenters argue that the effects of competition should be factored into the revenue stream by using the rates for capacity and energy actually offered or available in the utility's marketplace, such as incentive and special rates, not just the tariff rates to a particular customer.[818] Several commenters support removal of rate of return-related revenues associated with stranded assets, including risk premiums that are designed to compensate for potential nonrecovery of stranded costs.[819] EEI, in contrast, opposes any disallowance of rate of return-related revenues on the grounds that such a disallowance would violate the constitutional bar against the taking of private property without just compensation. Electronic Data Systems recommends calculation of the revenue stream using projected rates that include the effects of future rate increases.

The Commission requested comments on what categories of costs, in addition to investment costs, should be eligible for stranded cost recovery. In response, many commenters support the inclusion in the revenue stream calculation of additional costs, termed ''special'' costs, that may not be currently reflected in the rates paid by the departing customers, but that were incurred to provide service to these customers.[820] ''Special'' costs include: (1) Nuclear decommissioning costs; (2) environmental obligations existing at the time of the customer's departure; (3) purchased power contracts; (4) buyouts and buydowns of purchased power contracts; and (5) all regulatory assets, including deferred costs of generating assets for which regulators have promised recovery, deferred taxes, transition costs for post-employment benefits other than pensions, and contingent liability.

Other commenters oppose the inclusion of ''special'' costs in the calculation of the revenue stream.[821] TAPS questions how a customer can be held responsible for a cost that, by definition, it was never under a contractual obligation to pay. WP&L states that suppliers' rates should already reflect reasonable estimates of decommissioning costs and, therefore, no additional recovery is warranted.

Some commenters argue that the calculation of stranded costs should include social costs, such as demand side management, environmental costs, low income assistance costs, and costs associated with the management of fish and wildlife.[822]

NARUC states that the Commission should not preempt the ability of states to establish competitively neutral programs, such as DSM and energy efficiency, environmental mitigation, and R&D.

Various commenters state that any determination of stranded costs should take into account all offsetting benefits realized by the transmission provider upon a customer's departure.[823] Some commenters describe these costs as ''stranded benefits.'' [824]

Most commenters favor the removal of avoided variable costs from the calculation of stranded costs on the basis that only fixed costs are truly stranded.

Some commenters support prioritizing stranded cost recovery.[825] These commenters argue that stranded costs should be categorized and ranked by the degree of responsibility that utilities had for their incurrence. Utilities would be allowed the greatest percentage of recovery for those stranded costs over which they had the least control.

Definition and Calculation of the Competitive Market Value

There generally was no consensus among the commenters concerning how

[809] *E.g.*, TDU Systems, Blue Ridge, NY Energy Buyers.

[810] *E.g.*, UT Com.

[811] *E.g.*, Utility Investors Analysts, Public Power Council, Atlantic City, EEI, PA Com, NYSEG, Central Montana EC, Nebraska Public Power District, LG&E ABATE.

[812] Several commenters (Illinois Power, Oklahoma G&E, and Utility Investors Analysts) suggest that the Commission hold a technical conference to discuss how best to define the calculation of the formula components.

[813] Central Montana EC and NY Energy Buyers.

[814] *See* EEI, Electronic Data Systems, Knoxville, NIMO, NYSEG, NY Energy Buyers, Reynolds.

[815] *E.g.*, Nuclear Energy Institute, EEI, Consumers Power, PA Com, Oklahoma G&E, Portland, Knoxville, MidAmerican, Seattle, Salt River, Washington and Oregon Energy Offices, SMUD, Caparo.

[816] Some commenters (*e.g.*, Alma, Freedom Energy) oppose such flexibility. Alma maintains that clarity of rules is needed to provide participants in the competitive market as much certainty as possible about stranded cost charges likely to be recovered before they engage in alternative transactions. Freedom Energy similarly supports across-the-board or generic standards, as opposed to a case-by-case approach.

[817] *E.g.*, Centerior, Com Ed, Duke, Entergy, Florida Power Corp, Utility Investors Analysts, CA Energy Co, CSW.

[818] *E.g.*, Alma, ABATE, DOD, TDU Systems, ELCON.

[819] *E.g.*, NRECA, CA Energy Co, ABATE, DOD.

[820] *E.g.*, EEI and various investor-owned utilities, Nuclear Energy Institute, NC Com, Legal Environmental Assistance, EPA, Utilities for Improved Transition, PA Com.

[821] *E.g.*, TAPS, WP&L, UT Industrials, UtiliCorp, American Forest & Paper.

[822] *E.g.*, DC Com, Sustainable Energy Policy, Washington and Oregon Energy Offices.

[823] *E.g.*, AEC & SMEPA, Electronic Data Systems, Freedom Energy Co, LG&E, American National Power, EGA, Entergy, AMP Ohio, TDU Systems, TAPS, Las Cruces.

[824] TDU Systems proposes that the Commission allow for the recovery of stranded benefits in one of two ways: (1) Require direct payment of stranded benefits to a wholesale purchaser whose contract is terminated; or (2) allow a party to continue to receive power at cost-based rates for a period sufficient for the purchaser to be ''transitioned'' into a competitive market.

[825] *E.g.*, ELCON, NY Energy Buyers, SMUD, Caparo.

to determine the revenues a utility would receive in a competitive market for the stranded assets, that is, the competitive market value.[826] Proposals for calculating competitive market value include using: (1) The marginal cost of the released capacity; (2) the long-run marginal cost of the most competitive incremental generation replacement technology; (3) the marginal cost of requirements service; (4) a combination of the marginal costs of the utility, alternative suppliers, and others; (5) the cost of a combined cycle combustion turbine; (6) the price paid by the departing generation customer; (7) the highest price available in the market; and (8) auctions. In addition, to the extent that a futures market is sufficiently well-developed when the Commission issues a final rule, several commenters believe that futures market prices could be used as an estimate of market value.[827]

MT Com contrasts the effect of using short-term nonfirm prices instead of long-term firm prices as the competitive market value. It states that if short-term nonfirm prices are used, the stranded cost estimate would be higher, because the market price of short-term nonfirm power is lower than both the market price of long-term firm power and the embedded cost price.

Some commenters express concern regarding the difficulty of determining the market value of the displaced capacity under the revenues lost approach.[828] Among other things, commenters note that because a competitive market does not yet exist, the market price cannot be calculated in advance. For this reason, several commenters support an after-the-fact determination of market value.[829]

Snapshot Approach vs. True-Ups

Commenters are split on whether the revenues lost approach should use a one-time snapshot approach[830] or whether true-ups should be required or allowed.[831] The primary rationale offered in support of a snapshot approach is certainty;[832] the primary rationale offered in support of true-ups is accuracy.

Commenters that support true-ups note the inaccuracy associated with long-term avoided cost estimates contained in PURPA-mandated QF contracts and maintain that the projections required by the revenues lost approach will produce similarly disastrous results if true-ups are not permitted. As a component of the true-up calculation, some commenters favor inclusion of revenues associated with future load growth of remaining customers.[833] According to Electronic Data Systems, if these revenues are not included in a true-up calculation, the utility could over- or under-collect stranded costs, depending on whether and what type of load growth is anticipated. CA Energy Co and American National Power recommend consideration of load growth of remaining customers as a mitigating factor because the load increases of these customers allow the sale of the stranded capacity. CSW, on the other hand, opposes using the future load growth of remaining customers as a mitigation device. CSW states that the benefits of growth on the former supplier's system should flow to the customers who remain customers of that system. Ohio Ed agrees, except where the customer proves that the utility has deferred or cancelled capacity resource additions in response to departing customers.

Other commenters suggest that the Commission should not prescribe one method over the other.[834] EGA, for example, states that customers should have the choice of paying either a projected fixed amount or a charge that is periodically trued up.

Mitigation

A number of commenters agree that the revenues lost approach effectively encompasses mitigation.[835] Others argue that mitigation should (or could) be accomplished through divestiture of assets or capacity auctions.[836] LG&E states that a utility requesting recovery of stranded costs should be required to auction that portion of its system to the highest bidder. The difference between the auction price and the depreciated value of the auctioned assets could be used to determine stranded costs. However, LG&E does not advocate complete recovery of this difference; rather, it argues that this amount could be used as a starting point.

Several commenters argue that the revenues lost approach can produce anticompetitive results if capacity auctions or divestiture are not required.[837] A number of these commenters contend that utilities that recover significant stranded costs (while still maintaining control over the stranded capacity) can use the freed capacity to make sales in the market at subsidized prices. They maintain that these utilities do not have to worry about recovery of fixed costs because those costs are recovered by the stranded cost charge. According to these commenters, utilities can then remarket (or ''dump'') stranded capacity at artificially low prices (made possible by the subsidy from the stranded cost recovery) and thereby gain a competitive advantage in other transactions.[838] If the utilities are permitted to remarket the displaced capacity, CA Energy Co states that market-sensitive floor prices should be set to prevent utilities from reselling power from stranded assets at artificially low prices.

Suggestions as to how to prevent such anticompetitive consequences include allowing the customer to own or control the residual asset or amount of stranded capacity equivalent to the lost revenues. According to EGA, the customer could market the capacity it would have had to pay for through stranded cost charges and thus prevent the utility from remarketing the capacity after it has been paid stranded costs.

Several commenters take a harder line and would require suppliers seeking stranded cost recovery to offer for sale to the departing customer a ''slice'' of their system.[839] TDU Systems states that the purchase of an undivided slice of the system is superior to divestiture of a specific asset because the utility cannot keep the wheat and leave the purchaser with the chaff. TDU Systems would also make purchase rights to the system assignable. According to TDU

[826] *E.g.*, Centerior, Duke, Entergy, Com Ed, Houston L&P, Florida Power Corp, Carolina P&L, NRRI, WP&L, DOE, CSW, UtiliCorp, LG&E, FL Com.

[827] *E.g.*, WP&L, DOD, Duke, PSNM, ABATE, Houston L&P. The Commission notes that the New York Mercantile Exchange only recently began trading in electricity futures and that such trading was limited to two delivery points located within the Western Interconnection.

[828] *E.g.*, MI Com, NSP, NY Energy Buyers, KS Com.

[829] *E.g.*, KS Com, NY Energy Buyers.

[830] Commenters that support a one-time, up-front approach include FL Com, Dayton P&L, Portland, DE Muni.

[831] Commenters that support true-ups include ELCON, NYSEG, MN DPS, Reynolds, TAPS, NIMO, DOE, Electric Consumers Alliance, Com Ed, United Illuminating, SoCal Edison.

[832] DE Muni urges rejection of true-ups on the basis that true-ups represent guaranteed recovery of 100 percent of stranded costs.

[833] *E.g.*, Electronic Data Systems, Alma, American National Power, CA Energy Co, NARUC, NRECA.

[834] *E.g.*, Atlantic City Electric, EGA, Conservation Law Foundation.

[835] *E.g.*, Utility Investors Analysts, Duke, PSE&G, Com Ed, United Illuminating, Entergy.

[836] *E.g.*, NIEP, LG&E, TDU Systems, EGA, NY Energy Buyers, ELCON, American National Power.

[837] *E.g.*, LG&E, Allegheny, TDU Systems, EGA, AMP Ohio, CA Energy Co, WP&L, Torco.

[838] CA Energy Co maintains that an anticompetitive intent could be hidden by the argument that power must be dumped to mitigate stranded costs. It thus submits that, even without intending to do so, a utility could cripple competition by depressing market rates to artificially low levels.

[839] *E.g.*, TDU Systems, Arkansas EC.

Systems, this mitigation scheme is the only possible way to justify the revenues lost approach. TDU Systems argues that this proposal would inflict no harm on the utility, which would be fully compensated for the stranded assets. It also suggests that the ability to purchase a slice of the supplier's system would serve as an important bargaining tool in stranded cost negotiations, which would help level the playing field among the parties.

Other mitigation proposals include: (i) Requiring each utility to prepare a mitigation plan under the supervision of an independent expert that must be approved by the parties or by the Commission before stranded cost recovery is permitted;[840] (ii) requiring a utility to report annually for a five-year period its mitigation activities and to identify its stranded costs yet to be recovered;[841] and (iii) setting the market value of the displaced capacity at a high level (thereby reducing the stranded cost charge) to provide a mitigation incentive.[842] A number of commenters support customer-controlled mitigation, arguing, among other things, that the entity responsible for paying stranded costs has the best incentive to mitigate them.[843] Others support some form of utility sharing of stranded costs to give utilities an incentive to mitigate stranded costs.[844]

b. Reasonable Expectation Period (Period of Expected Continued Service)

Numerous commenters oppose setting absolute limits on the period over which a customer's liability for stranded costs would be determined.[845] They suggest instead that the Commission should apply the facts of each case, including the facts used to prove a reasonable expectation of continued service, to its determination of a reasonable expectation period. Among the factors commenters propose for consideration are: the utility's planning horizon; the average remaining life of the utility's generating facilities or a specific number of years that coincides with the duration of a utility-specific stranded cost recovery plan; utility projected load growth; dedicated facility construction lead times; estimated time to market stranded assets; the lesser of the utility's need date for new generation or the cross-over date when the market generation price is expected to equal a customer's embedded cost less other charges and compensation; and the period for which estimated revenues exceed market values. Commenters representing the financial community[846] oppose limiting cost recovery from the departing generation customer based on the term of the contract. They argue that it was reasonable for a utility to expect to continue to serve a customer, or customers who would take its place, through the life of the assets; otherwise, the asset could not have been financed in the first place.

A number of other commenters urge the Commission to prescribe limits on a customer's maximum liability.[847] Some commenters believe that the utility's planning horizon is the reasonable expectation period.[848] PSE&G states that since utilities invested and incurred costs to serve customers based on the planning horizon, the planning horizon is the only logical period. Other commenters propose that the reasonable expectation period be limited to one contract extension period, or to the shortest of: (i) One additional contract renewal period; (ii) the utility's planning horizon; (iii) the period it would/does take for load growth on the seller's system to absorb the lost load; or (iv) the contractual notice period.[849] Other suggested limits include the weighted average remaining life of all generating assets;[850] the in-service date of the utility's next avoidable generating unit or purchased power contract that is projected to have a capacity factor comparable to the departing generation customer's load factor minus a one-time mitigation effort;[851] and a rebuttable presumption that two years is the maximum time for a utility reasonably to expect to receive revenue from tariff sales or ''open-ended'' contracts.[852]

Other commenters propose recovery periods that range from three to five years (*e.g.*, Central Montana EC),[853] five years (*e.g.*, Public Power Council), and eight years (*e.g.*, Allegheny).[854]

GA Com and AZ Com state that stranded cost recovery should not go on indefinitely. GA Com states that stranded costs should be collected for a sufficient period of time to ensure full recovery and indifference on the part of the utilities' remaining native load customers. AZ Com states that a specific termination period will also create an incentive for utilities to mitigate stranded costs.

c. Proposed Stranded Cost Recovery Procedures

Several commenters[855] urge the Commission to be flexible in evaluating proposed mechanisms for recovery of stranded costs, including the payment method, noting that an approach suitable to one utility and its customers may not be suitable to another. They say that utilities within a region might find a mechanism that meets their region's unique characteristics.

Some commenters oppose certain aspects of the procedures proposed in the NOPR. For example, TAPS objects that the NOPR procedure aimed at providing advance notice to the customer of its potential stranded cost obligation resembles the procedure rejected in *Cajun*. It says that ''the customer will likely be forced to spend significant time and resources 'litigat[ing] to determine the price of a product(,)' thereby 'introduc[ing] deal-killing transactional costs and uncertainties.' '' (citing *Cajun*, 28 F.3d at 179). TAPS proposes that the seller be required to produce a stranded cost estimate that reflects a good faith, reasonable estimate of the likely impact of mitigation and that sellers making excessive and unsupported stranded cost claims be penalized. At a minimum, it argues that the seller should be held responsible for the costs

[840] *See, e.g.*, CA Energy Co.

[841] *See, e.g.*, PSNM.

[842] *See* WP&L.

[843] *E.g.*, EEI, PA Com, AMP Ohio, TAPS.

[844] *E.g.*, ABATE, Fertilizer Institute, IL Com, KS Com, San Francisco, UT Industrials, ELCON, CA Energy Co, MT Com, Caparo, WA Com, Education, NRRI, NY Energy Buyers, Reynolds, DOD, DC Com.

[845] *See, e.g.*, Florida Power Corp, Central and South West, Com Ed, EEI, Montana, PECO, Minnesota DPS, NIMO, NSP, SoCal Edison, PA Com, Central Louisiana, Utility Investors Analysts, Salt River, Orange & Rockland.

[846] *E.g.*, Utility Investors Analysts and Utility Shareholders.

[847] *E.g.*, NIEP, TAPS, Allegheny, Central Montana, Municipal Energy Agency Nebraska, PSNM, ABATE, ELCON, PSE&G, UtiliCorp.

[848] *E.g.*, PSE&G, PSNM, ELCON, Oklahoma G&E, Duke. Oklahoma G&E supports use of the utility's planning cycle for retail stranded costs and use of the contract term for wholesale stranded costs. Duke states that the Commission should permit the customer and the transmission provider to establish the compensation period at something less than the maximum period.

[849] *E.g.*, UtiliCorp, WP&L, Missouri Joint Commission, TAPS, Municipal Energy Agency Nebraska, TDU Systems.

[850] *E.g.*, Carolina P&L.

[851] *E.g.*, FL Com.

[852] *E.g.*, UT Industrials.

[853] Central Montana describes as ''excessive'' the recovery period offered to it by Montana. Central Montana states that it gave notice under a five-year notice provision and that Montana responded with a stranded cost demand extending 14 years after notice of termination (nine years from the date service would terminate).

[854] Allegheny would exempt three types of stranded costs from such a limit: (1) Those due to PURPA power purchases (it submits that these were federally-mandated rather than profit-motivated business decisions); (2) those due to regulatory assets (such as deferred taxes); and (3) those due to municipalization. In addition, it favors establishing a rebuttable presumption that these special costs are eligible for stranded cost recovery.

[855] *E.g.*, EEI, Centerior, PECO, Houston L&P, Salt River.

reasonably expended by the buyer to litigate the stranded cost claim.

DE Muni asserts that if filing a complaint to redress grievances related to the recovery of stranded costs is to be a meaningful remedy, the final rule should set a time limit within which the complaint must be resolved.

A number of commenters offer modifications to the recovery procedures set forth in the NOPR, including: (1) Extending a utility's response time for providing stranded cost liability estimates from 30 days to at least 60 days;[856] (2) requiring a utility to provide to each wholesale customer within six months of the effective date of the final rule: (a) The formula that the utility proposes to use to calculate the customer's maximum possible stranded cost exposure without mitigation; and (b) an actual calculation of the customer's stranded cost exposure assuming the customer left the utility's system six months after the effective date of the final rule;[857] (3) allowing customers that desire to litigate their stranded cost liability to do so in a forum in which all litigating customers participate;[858] (4) requiring utilities to disclose their estimated transition cost liabilities (and the nature of those liabilities) before the effective date of the final rule to permit a realistic evaluation of the scope of the transition cost problem and possibly facilitate resolution of some disputes by settlement;[859] (5) requiring any utility seeking stranded cost recovery to provide a list of the stranded facilities to the departing generation customer and offer that customer an equity position in those facilities in return for payment of stranded costs, thereby enabling the departing customer to recover some of its stranded costs payment when any of the facilities becomes useful again;[860] (6) requiring a ''good faith request'' for an estimate of stranded costs based on an expected date of departure from the providing utility's system and mitigation efforts expected to be undertaken by the utility;[861] and (7) requiring documented evidence that a utility made a good faith attempt to settle with a departing generation customer before the utility is given the opportunity to recover stranded costs.[862]

[856] *E.g.*, Entergy.

[857] *E.g.*, Associated Power.

[858] *E.g.*, Associated Power.

[859] *E.g.*, Texaco.

[860] *E.g.*, Heartland.

[861] *E.g.*, PSNM, ELCON.

[862] *E.g.*, ELCON.

Commission Conclusion

We reaffirm our proposal that the determination of recoverable stranded costs should be based on the ''revenues lost'' approach. We find that the revenues lost approach is the fairest and most efficient way to balance the competing interests of those involved.

After careful consideration of the comments submitted, we have decided to adopt the following formula for calculating a departing generation customer's stranded cost obligation (SCO), on a present value basis, under a revenues lost approach:

$$SCO=(RSE-CMVE\times L$$

where:

RSE=Revenue Stream Estimate—average annual revenues from the departing generation customer over the three years prior to the customer's departure (with the variable cost component of the revenues clearly identified), less the average transmission-related revenues that the host utility would have recovered from the departing generation customer over the same three years under its new wholesale transmission tariff.[863]

CMVE=Competitive Market Value Estimate—determined in one of two ways, *at the customer's option:* Option (1)—the utility's estimate of the average annual revenues (over the reasonable expectation period ''L'' discussed below) that it can receive by selling the released capacity and associated energy, based on a market analysis performed by the utility; or Option (2)—the average annual cost to the customer of replacement capacity and associated energy, based on the customer's contractual commitment with its new supplier(s).

L=Length of Obligation (reasonable expectation period)—refers to the period of time the utility could have reasonably expected to continue to serve the departing generation customer. We reaffirm that we do not believe that a one-size-fits-all approach is appropriate for determining the length of a customer's obligation. If the parties cannot reach agreement as to the length of the customer's obligation, this period is to be determined through litigation as a part of the threshold issue of whether the utility had a reasonable expectation of continuing to serve the customer.

Application of the foregoing formula and collection of the resulting stranded costs are subject to the following conditions:

1. Cap on SCO. The quantity (RSE–CMVE) can be no greater than the average annual contribution to fixed power supply costs (defined as RSE less variable costs) that would have been made by the departing generation customer had it remained a customer.

2. Changes in Customer Revenues. If the customer's rates (or *contract demand* amounts, if relevant) changed during the three-year period prior to the termination of its existing requirements contract, then the RSE should be calculated using the customer's most recent 12 months of revenue.

3. CMVE Option 2 Conditions. Option 2 (a CMVE equal to the average cost to the customer of replacement capacity and associated energy) would be available to a customer whose alternative purchase(s) runs concurrent with L, or, if longer than L, contains rates that do not fluctuate over the duration of the contract. The customer would be required to demonstrate (at the time it chooses this option) that the replacement capacity contract(s) is for service equivalent to the released capacity (that is, firm power for a period at least equal to L), and must also clearly identify the rates to be paid for the replacement service.

4. Payment Options. The method and term of payment should be negotiated, but is ultimately left to the customer's discretion. Possible payment options include a lump-sum payment, an amortization of a lump-sum payment over a reasonable period of time, or a surcharge on the customer's transmission rate.

5. Applicability. The formula is designed for determining stranded costs associated with departing wholesale generation customers and for retail-turned-wholesale customers.[864]

6. Marketing/Brokering Option. The Commission will allow the customer, at its sole discretion, a choice to market the released capacity and associated energy (or to contract with a marketer for such service). Alternatively, the customer may choose to broker the released capacity and associated energy (or to contract with a broker).[865]

[863] In the case of a retail-turned-wholesale customer, subtraction of distribution system-related costs may also be appropriate.

[864] The formula is not to be used for recovering stranded costs associated with retail wheeling. We believe the formula is unworkable in this scenario because one of its key elements—the option for a customer to market or broker the utility's power—may not be practicable for retail customers. Therefore, stranded costs associated with retail wheeling will be determined on a case-by-case basis.

[865] The customer may also decide to remain a requirements customer for L. If the customer elects to remain a requirements customer, the utility will be obligated to continue service to the customer for the duration of L.

7. Released Capacity and Associated Energy. A utility requesting stranded cost recovery must indicate the amount of system capacity and the amount of associated energy released by the departing generation customer and used in the revenues lost calculation. This will allow the departing generation customer to fairly consider exercising a choice to market or broker the released capacity and associated energy.

The formula balances a number of goals, including: (1) Ensuring full recovery of legitimate, prudent and verifiable stranded costs; (2) requiring the utility to mitigate stranded costs; (3) providing certainty for departing generation customers; and (4) creating incentives for the parties to renegotiate their existing requirements contracts or otherwise settle stranded cost claims without resort to litigation.

Contrary to the objections of some commenters that the revenues lost approach creates no incentive to mitigate stranded costs, the formula automatically encompasses mitigation by reducing the departing generation customer's stranded cost obligation by the competitive market value of the released capacity and associated energy. Further, the option provided in the formula for a customer to market or broker the released capacity and associated energy protects the customer from a utility trying to overrecover stranded costs by estimating a low value for the released capacity and associated energy and thereby provides the customer some assurance that stranded costs will be minimized. Specifically, if a customer believes the utility's competitive market value estimate (CMVE) is too low, it can market or broker the released capacity and associated energy and reduce its stranded cost obligation.[866] We accordingly will not impose a separate mitigation obligation on the utility above that which is already subsumed in the revenues lost approach. In addition, a utility will continue to be subject to an ongoing prudence obligation to sell excess capacity off-system and/or to dispose of uneconomic assets.

We recognize that some commenters oppose the revenues lost approach as imprecise. However, any ratemaking method that relies on estimates will be subject to forecasting error. Moreover, in direct response to commenter concerns, we have gone to great lengths in this rule to provide specificity with respect to the calculation of the components of the formula. We believe that use of the formula will narrow the scope of disputes over the calculation of stranded costs, lend precision to the stranded cost amount it produces, and provide certainty to departing generation customers with respect to their stranded cost obligations.

Calculation of the Revenue Stream Estimate (RSE)

The RSE component of the formula is based on revenues paid by the departing generation customer during the last three years of its contract or retail service. We believe that the use of ''present'' revenues in the calculation of the revenue stream has numerous advantages over other approaches advocated. The use of present revenues eliminates disputes over estimates of future revenues, thereby adding certainty to the calculation. It also eliminates the need for a detailed listing of includable costs, relying instead on the assumption that present rates include all of the utility's costs of providing service. Further, the rates that produce present revenues have been approved by regulators, which strongly suggests that the costs included in them are prudent, legitimate and verifiable.[867]

We reject the suggestion by commenters that a utility be required to calculate the revenue stream using any lower rate being offered by the utility for service comparable to that being taken by the customer when the customer departs the utility's generation system. A revenue stream calculated in this manner could deny a utility the opportunity to fully recover its stranded costs or could shift costs to other customers, a result we find unacceptable. Similarly, the elimination of return-related revenues from the revenue stream effectively would require shareholders to absorb stranded costs, which is contrary to our determination that a utility is entitled to an opportunity to fully recover legitimate, prudent and verifiable stranded costs.

Calculation of the Competitive Market Value Estimate (CMVE)

We recognize the difficulty associated with estimating the competitive market value of the capacity and associated energy not purchased by the departing generation customer. However, we believe that an up-front estimate, which provides flexibility to the utility and a measure of certainty to customers, is superior to other proposals, provided the right mix of incentives and options is included in the formula.

A utility requesting stranded cost recovery must estimate CMVE based on a market analysis, with all assumptions and work papers made available to the departing generation customer. This provides a utility with the flexibility to choose the methodology that it feels produces the best estimate of the competitive market value of the released capacity and associated energy. We note that numerous proposals for calculating competitive market value were made in the comments. The Commission believes that the flexibility provided by the formula we adopt in this Rule permits the filing utility to avail itself of many of these recommendations.

At the same time, a utility may have an incentive to underestimate CMVE and thereby increase the stranded costs charge. To address this issue, the formula contains several features designed to create an incentive to produce a good faith estimate of stranded costs and to safeguard customers if a utility fails to do so. For example, the formula provides a departing generation customer with the option to market or broker the released capacity and associated energy if it believes the utility's estimate is too low. If the marketing option is chosen, the customer would buy the released capacity from the utility at the utility's market value estimate. The associated energy would be purchased at the utility's average system variable cost. The customer would then resell the released capacity and energy and keep the resulting revenues. If the revenues it receives are greater than the utility's market value estimate, the customer will have reduced its stranded cost obligation. If the customer chooses the brokering option and the released capacity and associated energy are purchased by a third-party for more than the utility's market value estimate, the difference between the average annual revenues produced by the sale and the utility's CMVE estimate will be used to lower the customer's stranded cost obligation. The utility may be required to show in a compliance filing that it has reduced the customer's stranded cost obligation under such circumstances.

If the customer chooses CMVE Option 2 and meets its conditions, CMVE will be set at the average price that the customer pays its new supplier. The customer will test the market and choose the best deal available. Hence,

[866] This option also addresses the concerns of commenters that, by failing to require auctions or divestiture of stranded capacity, the Rule would allow a utility recovering stranded costs to sell the freed capacity at subsidized prices, thereby gaining a competitive advantage in other transactions. If the customer avails itself of this option, the utility would no longer control the released capacity.

[867] The present rates, whether established by settlement or otherwise, have been found to be just and reasonable. In other words, they are neither confiscatory nor exorbitant.

the price the customer pays its alternative supplier is arguably a more accurate measure of the competitive market value of the capacity and associated energy not taken from the host utility. Whether to exercise Option 2 resides solely with the customer.

We further note that the sale of all or part of a utility's generating assets could be used as a method to determine competitive market value of such assets. Under the theory that an asset sale price reflects the highest value for the utility's assets, the Commission would presume that the competitive market value established under an open asset sale (*i.e.*, an offer to sell assets to any taker) would fully satisfy the utility's responsibility to minimize stranded costs. If a stranded cost claim involves divestiture of assets, the amount of stranded costs associated with those assets would be the book value less the sale price. The Commission would determine the appropriate stranded cost charge based on the facts presented.

Snapshot Approach Versus True-Ups

The revenues lost formula is based on a one-time snapshot approach. We favor this approach over the true-up approach because it creates certainty and will produce reasonably accurate results. True-ups, on the other hand, while theoretically more accurate, require periodic recalculation of stranded costs, which creates ongoing uncertainty and disputes. In addition, true-ups will result in additional transaction costs. We believe that an approach that provides certainty and establishes cost responsibility up front is best for what is fundamentally a transition issue.

Implementation Procedures [868]

In the Supplemental Stranded Cost NOPR, we proposed procedures to provide a potential departing generation customer with advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[869] These procedures are modified as follows to incorporate the findings made in this rule:

(1) A customer may, at any time before the termination date specified in its existing wholesale requirements contract,[870] request the public utility to provide an estimate of the customer's stranded cost obligation based on the revenues lost formula contained in this Rule,[871] as of the date set forth in the customer's request. The customer should specify in its request, to the extent possible, pursuant to its rights under its power sales requirements contract with the seller,[872] the date on which the customer is considering substituting alternative generation for the requirements purchase and the amount of the substitute generation. Any remaining generation requirements to be purchased from the existing supplier after this date should be clearly indicated. The customer may seek further information on how the stranded cost charge would vary as a result of choosing different dates or different amounts of substitute purchases. The customer also should indicate its preferred payment method, such as a lump-sum payment, an amortization of a lump-sum payment, or a surcharge (such as monthly or annual) on the customer's transmission rate.

(2) The utility shall, within thirty days of receipt of the request, or other mutually agreed-upon period, provide the customer with an estimate of the customer's stranded cost obligation. The response shall include: (i) Estimates of RSE, CMVE, and L according to the revenues lost formula and based on the information supplied by the customer; (ii) supporting detail (including the underlying market analysis that forms the basis for the CMVE estimate) indicating how each element in the formula is derived to enable the customer to understand the basis for each element; (iii) a detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract; [873] (iv) an estimate of the amount of released capacity and the amount of associated energy that would result from the customer's departure, based on the information supplied by the customer, including detailed support for the amount of the released capacity and the amount of associated energy, and the market value of each, for each year of the reasonable expectation period, and how those amounts are consistent with the RSE and CMVE estimates; and (v) the utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs (the proposed modification should also reflect the customer's chosen payment method).

(3) If the customer believes that: (i) The utility has failed to establish that it had a reasonable expectation of continuing to serve the customer beyond the contract term; [874] (ii) the proposed stranded cost charge (or any of the elements used to compute it) is unreasonable; (iii) the amount of released capacity and the amount of associated energy assumed to be sold is unreasonable; or (iv) the utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs is unreasonable, the customer will have thirty days in which to respond to the utility explaining why it disagrees. The Commission expects parties to attempt to resolve any disputed issues.

(4) If the parties are unable to resolve the matter using the procedures in (1)–(3) above, the customer may either: (a) File a petition for declaratory order, or a section 206 filing seeking to amend an existing requirements contract, to seek a Commission determination as to whether: (i) The utility has met the reasonable expectation standard; (ii) the proposed stranded cost charge satisfies the other evidentiary standards set forth in this Rule; (iii) the amount of released capacity and the amount of associated energy proposed by the utility is reasonable; or (iv) the utility's proposal for any contract amendment needed to implement the customer's payment of

[868] These procedures apply to a potential departing generation customer who is an existing wholesale requirements customer of a public utility, or a retail customer of a public utility who is contemplating becoming a wholesale transmission customer (such as through municipalization). They may be used at the option of the potential departing generation customer. An existing wholesale requirements customer may use the procedures in conjunction with, or in lieu of, a complaint under section 206 to amend its existing requirements contract to add an explicit stranded cost provision, as discussed in Section IV.J.5.

[869] FERC Stats. & Regs. ¶ 32,514 at 33,114–15; 33,128–29.

[870] If the customer is a retail customer contemplating becoming a wholesale transmission customer, it may at any time request the public utility to provide an estimate of its stranded cost obligation.

[871] Because the formula reduces a customer's stranded cost obligation by the competitive market value of the capacity and associated energy that would be released by the customer's departure, we will not adopt the proposal in the Supplemental Stranded Cost NOPR to allow a potential departing customer to receive an estimate of the customer's ''maximum possible stranded cost exposure without mitigation.'' Requiring the utility to provide an estimate that reflects the competitive market value of the capacity and associated energy to be released will better enable the customer to assess its supply options.

[872] If the customer is a retail customer contemplating becoming a wholesale transmission customer, it should specify in its request, to the extent possible, the date on which the customer is considering becoming a wholesale transmission customer of the utility and the amount of generation, if any, it will continue to purchase from its existing supplier.

[873] If the customer is a retail customer contemplating becoming a wholesale transmission customer, the utility should provide a detailed rationale justifying the basis for its reasonable expectation of continuing to provide the customer bundled retail service.

[874] Subsection (i) above also would apply to a retail customer contemplating becoming a wholesale transmission customer if the customer believes that the utility has failed to establish that it had a reasonable expectation of continuing to provide the customer bundled retail service.

stranded costs is reasonable; *or* (b) wait until the proposed stranded cost charge is filed by the utility under section 205 of the FPA, and contest it at that time.[875] In either case, because estimates of RSE and CMVE may change over time, any estimate of stranded costs provided by a utility to a customer will not be considered binding prior to any filing by either party with the Commission. However, any stranded cost estimate filed by the utility in a section 205 or 206 proceeding, or in response to a petition for a declaratory order, shall be considered to be a binding estimate of the customer's maximum stranded cost obligation for purposes of litigation. Similarly, any estimate of stranded cost obligation filed by a customer in a petition for declaratory order or a section 205 or 206 proceeding shall be considered to be a binding estimate of the customer's minimum stranded cost obligation for purposes of litigation.[876] Estimates of stranded cost obligation that are filed by either party with the Commission shall include the information, including the supporting detail, identified in (2) above.

(5) If a utility intends to file for stranded cost recovery from a customer through either a stranded cost amendment to its existing contract or a surcharge on transmission rates, it must file its stranded cost estimate no later than 120 days prior to the end of the customer's contract term. The filing shall include the information, including the supporting detail, set forth in (2) above. The customer, of course, may contest the contents of such a filing.[877]

Conditions of the Marketing/Brokering Option

A customer may choose to market or broker a portion or all of the released capacity and associated energy identified by the utility in its stranded cost estimate (or to contract with a marketing/brokering agent). Importantly, by exercising the marketing or brokering option, the customer does not relinquish its right to contest any aspect of the utility's stranded cost estimate, including whether the utility is entitled to recover stranded costs for the period that the customer has agreed to market or broker any released capacity and associated energy. To implement this option, a customer must inform the utility in writing of its decision no later than 30 days after the utility files its estimate of stranded costs for the customer with the Commission. Before marketing or brokering of the released capacity and associated energy can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount of capacity and associated energy the customer is entitled to schedule, the price of capacity and associated energy, and the duration of the customer's marketing/brokering of the released capacity and associated energy. Parties are encouraged to settle disputes over these and any other marketing/brokering implementation issues. The negotiations should be guided by the principle that the utility must allow the customer to market or broker the released capacity and associated energy under terms and conditions comparable to those for a utility resale of the capacity and associated energy to a third party. If agreement over marketing or brokering cannot be reached, the parties may seek to include the issue as a part of a proceeding initiated at the Commission with respect to the utility's stranded cost estimate for the customer.[878] Upon issuance of an order resolving the disputed issues, the customer may reevaluate its decision to exercise the marketing/brokering option. The customer also may choose to market or broker any released capacity and associated energy not being marketed or brokered under an earlier agreement with the utility. A customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

Payment for Released Capacity and Associated Energy Under the Marketing Option

If the customer chooses to market released capacity and associated energy, it shall pay the utility's estimate of the competitive market value of the capacity, or, if the marketing option is exercised after a Commission order, it shall pay the competitive market value amount as determined by Commission order. In addition, for all energy scheduled to be delivered, the customer shall pay the utility's average system variable costs. The customer may also choose to market only a portion of the released capacity and/or for a shorter period. In this situation, the customer will also pay the competitive market value for the released capacity plus the utility's average system energy costs. The customer's liability for payment of stranded costs is unaffected by its decision to market released capacity and associated energy.[879] In addition, to the extent that the customer chooses to market a portion or all of the capacity alleged by the utility to be stranded, a final determination with respect to the customer's stranded cost obligation will not affect any prior marketing agreement.

Payment for Stranded Costs Under the Brokering Option

If the customer chooses to broker a portion or all of the released capacity and associated energy, any revenue received from such brokering activity shall be used to offset the utility's estimate of the competitive market value of the brokered capacity and associated energy.[880] Once a brokering agreement is executed between the customer and the utility, if the customer's brokering efforts fail to produce a buyer within 60 days of the date of that agreement, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula.

[875] As discussed above, retail customers contemplating becoming wholesale transmission customers may use the same procedures. As also discussed above, customers under existing requirements contracts with public utilities have the option of making a filing under section 206 seeking to amend the contract to add an explicit stranded cost provision, without having to go through these procedures.

[876] Although estimates by the utility or the customer may be binding for purposes of litigation, this does not mean that the parties may not settle at any time on another amount.

[877] A customer requesting a section 211 order for transmission services from a transmitting utility also may incur a stranded cost obligation. Any estimate of stranded cost obligation resulting from the requested transmission services should be included as part of the utility's good faith response to the customer's request for transmission services. *See* 18 CFR 2.20. Because the Commission will apply the revenues lost formula to any request for stranded cost recovery as a part of its determination of the appropriate charge for transmission services ordered in a section 211 proceeding, we encourage non-public utilities to use the revenues lost formula to estimate a customer's stranded cost obligation.

[878] Because litigation of stranded costs may extend beyond the date of the customer's departure, the customer may also file a petition for a declaratory order requesting expedited resolution of marketing or brokering implementation issues.

[879] If the customer can market the released capacity and associated energy for a higher price than the customer paid for it, the customer effectively reduces its stranded cost obligation, *i.e.*, the incremental revenue received offsets a portion of the customer's stranded cost payment to the utility.

[880] For example, if the customer brokers any released capacity and associated energy for a higher price than the utility's estimated competitive market value of that capacity and energy, the difference between the utility's estimate and the brokered price will be used to increase the utility's CMVE component of the stranded cost calculation, thereby reducing the customer's stranded cost obligation.

10. Stranded Costs in the Context of Voluntary Restructuring

In the Supplemental Stranded Cost NOPR, we noted that the functional unbundling of wholesale services does not require corporate unbundling (such as disposition of assets to a non-affiliate, or establishing a separate corporate affiliate to manage a utility's transmission assets). At the same time, we indicated that some utilities may ultimately choose some form of corporate unbundling.[881] We reaffirm in this Final Rule that we are willing to consider case-specific proposals for dealing with stranded costs in the context of any restructuring proceedings that may be instituted by individual utilities.

11. Accounting Treatment for Stranded Costs Comments

A number of commenters ask the Commission to provide accounting treatment guidance as part of its procedures for implementing its policies on stranded costs and their recovery.[882]

NSP states that the Commission will need to provide appropriate accounting guidance for the final stranded cost recovery methodology, including accounting for any portion of stranded cost recovery representing capital costs, the effect of any interperiod differences between the stranded cost calculations and the authorized recovery period, and the effects of differences between book and income implications of the stranded cost recovery mechanism. NSP also asserts that, in addressing the accounting implications of the final rule, the Commission must consider the requirements of the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 121, ''Impairment of Long-Lived Assets'' (SFAS No 121).

NASUCA states that one of the Commission's stated goals in providing stranded cost recovery is to protect against cost shifting. NASUCA argues that the Commission should adopt an accounting rule that assures that any federal resolution of wholesale stranded costs does not impose any cost shifting to captive customers.

EEI and Centerior argue that the Uniform System of Accounts as presently configured does not support the Commission's proposed policies on stranded cost recovery. Further, EEI states that even with the revenues lost approach, which EEI supports, utilities will still have to account for their assets on a class-of-asset by class-of-asset basis. EEI argues that this is necessary to ensure that the costs of the assets are expensed in the proper accounting period. EEI states that one of the basic principles of financial accounting is that expenses should be matched with the related revenues.

Commission Conclusion

As discussed in Section IV.J.3, this rule adopts a direct assignment approach for the recovery of stranded costs from departing generation customers. Under the revenues lost approach, stranded cost recovery is limited to the departing generation customer's contribution to fixed costs that the utility otherwise would not recover because of the customer's departure.

We recognize that there are certain similarities between the financial reporting objectives of SFAS No. 121 and the determination of stranded costs. However, there are also important differences between SFAS No. 121 and our approach to stranded costs. The revenues lost approach does not attempt to identify specific uneconomic assets and is not limited to only long-lived assets. Instead, it uses a formulary methodology that encompasses all fixed costs of providing service.

From a financial accounting standpoint, our approach to stranded costs creates the potential for a mismatch between the periods in which the stranded costs are charged to expense and any revenues provided for their recovery are included in net income determinations. This is because the earning process entitling a utility to the benefits of stranded cost recovery and thereby requiring the recognition of revenue may be completed prior to the time that the stranded costs must be charged to expense under generally accepted cost recognition criteria. This circumstance in a cost-based regulated environment creates the undesirable potential for double recovery of the same cost, cost shifting, and inappropriate financial reporting.

In order to avoid this potential, utilities shall not recognize revenues intended to provide for recovery of stranded costs from wholesale requirements customers prior to the time that the stranded costs are charged to expense, unless prior Commission approval to do so has been obtained. Absent Commission approval, utilities shall defer such amounts in Account 253, Other Deferred Credits, and amortize them to Account 456, Other Electric Revenues, consistent with the period the related costs are charged to expense. Also, we will require a utility to submit its proposed accounting for stranded costs and related revenues as part of its rate filing requesting recovery of stranded costs under section 205 of the FPA.

12. Definitions, Application, and Summary

In the Supplemental Stranded Cost NOPR, the Commission described proposed amendments to our regulations to establish filing requirements for public utilities and transmitting utilities that seek stranded cost recovery. We proposed to define ''wholesale stranded cost'' as ''any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: (i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility, or (ii) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.'' We sought comments on whether this definition should encompass the situation where a wholesale requirements customer ceases to purchase power from the utility that had been making wholesale requirements sales to such customer without becoming an unbundled transmission services customer of that utility.[883]

Comments

We received numerous comments both supporting and opposing revisions to the proposed definition of wholesale stranded costs.[884] Several commenters oppose broadening the definition to include costs stranded by customers that do not become unbundled transmission service customers of the former supplier.[885] For example, EGA argues that the loss of an industrial customer that chooses to self-generate or the loss of a requirements customer as a result of a newly-created municipal system that interconnects with a transmitting utility that is not the customer's former supplier could have happened at any time. EGA states that revenues lost as a result of either

[881] FERC Stats. & Regs. ¶32,514 at 33,132.

[882] *See, e.g.*, EEI, NSP, LILCO, Central Hudson, Deloitte & Touche, Centerior.

[883] FERC Stats. & Regs. ¶ 32,514 at 33,115.

[884] EEI asks the Commission to expand the definition of stranded costs to account for the case where the Commission has proposed to address purely retail stranded costs (that is, where a state regulatory authority does not have authority to address stranded costs at the time that retail wheeling is required). However, the regulations will contain a definition of ''retail stranded costs'' to account for this case. *See* § 35.26(b)(5) of the Final Rule.

[885] *E.g.*, EGA, Direct Service Industries, Memphis.

scenario have nothing to do with regulatory reforms and should not be considered ''stranded'' costs.

Other commenters disagree.[886] Puget asserts that permitting departing generation customers to avoid paying stranded costs if they do not take unbundled transmission from their former suppliers would create an incentive for departing customers (or their new electric suppliers) to build unneeded and uneconomic new transmission lines. Puget says that it also could be a disincentive to engage in regional transmission planning and coordination because the existence of new transmission facilities needed to achieve regional reliability and efficiency may increase the likelihood that departing generation customers could import their power supplies over those new facilities and avoid paying the utility's stranded costs.[887]

Some of these commenters propose using an exit fee to collect stranded costs from a customer that does not take unbundled transmission from its former supplier, since a transmission surcharge is not available in this circumstance.[888] Other methods proposed include: (1) Conditioning Commission approval of the transmission rates or wholesale power rates charged by the transmission-providing utility upon the inclusion of a surcharge to recover the former supplier's stranded costs or upon the transmission-providing utility otherwise agreeing to guarantee the payment of the stranded costs or act as billing agent for the former supplier;[889] (2) authorizing the former supplier to levy a stranded cost charge on the transmission-providing utility (if that utility is interconnected with and has transmission contracts with the former supplier); (3) if a retail customer becomes annexed to a municipal utility and does not take unbundled transmission services from its former supplier, permitting recovery of stranded costs from the municipal utility through its jurisdictional transmission rates; or (4) requiring a public utility providing transmission service for a customer that has left its former supplier to agree, as a condition to recovery of its own stranded costs, to ensure the payment of any stranded costs incurred by the former supplier.[890]

Commenters also address the use of the terms ''legitimate, prudent, and verifiable'' in the definitions of wholesale and retail stranded costs. Several commenters suggest that the Commission's use of the word ''prudent'' could imply that utilities have to relitigate the prudence of costs that the Commission and state commissions have already approved; these commenters believe that utilities should not have to relitigate prudence.[891] Some argue that once a regulatory agency (state or federal) has allowed recovery of the costs in rates, or promised future recovery, utilities should not have to undergo a second regulatory review to recover those costs if they become stranded.[892]

Commenters recommend that the Commission address this situation by: Striking the word ''prudent'' from the definition or specifying that the prudence requirement is satisfied by previous regulatory authorization;[893] dropping the terms ''legitimate, prudent and verifiable'' from the definition and using instead ''allowed,'' ''accepted,'' or ''allowable'';[894] or adding ''or approved by state commission'' after the words ''legitimate, prudent and verifiable'' in the definitions of both wholesale and retail stranded costs.[895]

Other commenters oppose these proposals, suggesting that the prudence analysis for stranded cost purposes may involve questions of prudence different from those that arise in a ratemaking context.[896] DE Muni objects that replacing ''legitimate, prudent and verifiable'' with ''allowed, accepted, or allowable'' could enable a utility to recover costs that the utility may not be able to prove were prudent, legitimate, and verifiable.

A number of commenters submit that ''legitimate, prudent and verifiable'' costs should not include the costs of uneconomic plants or costs resulting from utilities' independent business decisions (as distinguished from costs the utility was forced by regulation to incur).[897]

Several other commenters address the rule's application to wholesale requirements customers.[898] AMP-Ohio asks the Commission to clarify that the reference to ''wholesale requirements customer'' is to a full requirements customer, not a partial requirements customer. It says that no transmission provider should have any reasonable expectation of continuing to serve loads of partial requirements customers. TAPS suggests that references to ''new wholesale requirements contract'' in proposed § 35.26(c)(1) should be conformed to the defined term ''new contract'' in proposed § 35.26(b)(7). In addition, it suggests that the Commission clarify the regulations by clearly foreclosing stranded cost claims for ''new contracts'' without express exit fees, instead of simply failing to provide for such recovery.

Commission Conclusion

We will retain the definition of ''wholesale stranded cost'' proposed in the Supplemental Stranded Cost NOPR.[899] We believe it would be inappropriate to expand the definition to include the situation where a

[886] *E.g.*, Atlantic City, Carolina P&L, Consumers Power, Minnesota Power, Knoxville, Alma, Florida Power Corp, El Paso, Central Louisiana, Southern, WP&L, FL Com, Utility Investors Analysts, Florida Power Corp, El Paso, Central Louisiana, TDU Systems, NW Conservation Act Coalition, Puget, NU, EEI.

[887] Several commenters also ask the Commission to expand the definition of wholesale stranded cost to include the situation where a wholesale supplier loses wholesale load as a result of a requirements customer's loss of retail load because of retail wheeling, municipalization or retail taps from another utility's system. *E.g.*, Utilities For Improved Transition, Montaup, SC Public Service Authority. In addition, a number of commenters ask the Commission to treat the members of a single G&T cooperative system as a single economic unit and to revise the definition of wholesale stranded costs to allow a transmitting G&T cooperative (the arm of the cooperative system that provides the transmission) to recover the costs stranded when a retail customer of one of its member distribution cooperatives takes advantage of the open access environment by becoming a wholesale entity. *E.g.*, Big Rivers EC, NRECA, Tri-County EC, TDU Systems.

[888] *E.g.*, Carolina P&L, NU, Florida Power Corp, PSNM, Southern, Mountain States Petroleum Assoc, FL Com.

[889] In its reply comments, Memphis Light objects to the proposal that the Commission condition approval of all new power contracts for those customers that leave a utility's system without using the transmission services of the original utility upon the inclusion of a provision to recover the stranded cost for the previous power supplier. It argues that this proposal could result in nonrecovery from some customers because wholesale customers faced with such a provision would pursue non-jurisdictional contracts and/or generate within the confines of their own systems.

[890] *E.g.*, EEI, El Paso, NU, Atlantic City, PG&E, Coalition for Economic Competition, NW Conservation Act Coalition, Puget, NRECA, Cajun, East Kentucky, FL Com, Associated EC, Utilities For Improved Transition, TDU Systems, TVA.

[891] *E.g.*, EEI, NSP, Arizona, United Illuminating, Entergy, SCG&E, PECO, NRECA.

[892] *E.g.*, EEI, Centerior, NSP, SCG&E, PECO, Tucson Power, Arizona.

[893] *E.g.*, PECO, Entergy.

[894] *E.g.*, EEI, SCG&E, Carolina P&L.

[895] *E.g.*, Atlantic City. EEI also proposes that at the time of filing of a stranded cost recovery charge (whether as an amendment to a contract or a surcharge to a transmission rate), the Commission limit its inquiry to the issue of the stranded cost charge rather than allowing all aspects of a rate or contract to be opened up. EEI states that this is what the Commission did in the natural gas context, where it permitted limited rate filing cases under section 4 of the NGA.

[896] *E.g.*, Alcoa, Cleveland.

[897] *E.g.*, Mountain States Petroleum Assoc, Caparo, Torco.

[898] *E.g.*, AMP-Ohio, PA Munis, TAPS.

[899] For the reasons articulated below, we accordingly will reject the various revisions to the definition that were proposed by commenters.

wholesale requirements customer[900] (or a retail-turned-wholesale customer) ceases to purchase power from the utility without using the transmission services of that utility.[901] Any costs that the utility might incur as a result of the loss of the requirements customer in this scenario would be outside the scope of this Rule. The premise of this Rule is that, where a customer uses the new open access to obtain power from a new generation supplier, the customer must pay the costs that were incurred on its behalf under the prior regulatory regime. However, if a customer leaves its utility supplier by exercising power supply options (such as access to another utility's transmission system or self-generation) that do not rely on access to the former seller's transmission, there is no nexus to the new open access rules.[902] If a customer is able to obtain power from a new supplier by using the transmission system of another utility, it is likely that the customer could have made these arrangements in the absence of the new open access rules. The new transmission provider would have had little incentive to deny transmission services to the customer in order to protect an existing power supply arrangement, since it was not the customer's power supplier in the first place. Indeed, it is likely that the neighboring utility would have a positive incentive to provide the transmission service in order to increase its revenues. This incentive is unchanged by open access transmission.

Some commenters have asked us to eliminate the term ''prudent'' from the definition of stranded costs. We will not do so; we will retain the requirement that stranded costs be ''legitimate, prudent and verifiable.'' A determination that a utility had a reasonable expectation of continuing to serve a customer would not, in all circumstances, mean that costs incurred by the utility were prudent. Prudence of costs, depending upon the facts in a specific case, may include different things: *e.g.,* prudence in operation and maintenance of a plant; prudence in continuing to own a plant when cheaper alternatives become available; prudence in entering into purchased power contracts, or continuing such contracts when buy-outs or buy-downs of the contracts would result in savings. The Commission therefore cannot make a blanket assumption that all claimed stranded costs will have been prudently incurred. However, we clarify that we do not intend to relitigate the prudence of costs previously recovered.[903]

Thus, this Rule will permit a public utility or transmitting utility to seek recovery of wholesale stranded costs as follows. First, for stranded costs associated with new wholesale requirements contracts (that is, any wholesale requirements contract executed after July 11, 1994), the regulations will allow recovery of stranded costs only if the contract contains an explicit stranded cost provision that permits recovery. By ''explicit stranded cost provision'' we mean a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate.. We clarify that provisions in requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that explicitly reserved the right to stranded cost recovery pending the outcome of this Rule will be deemed ''explicit stranded cost provisions.'' However, provisions in requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that postpone the issue of stranded cost recovery without specifically providing for recovery of stranded costs will not be considered ''explicit stranded cost provisions.''

Second, for existing wholesale requirements contracts (that is, any wholesale requirements contract executed on or before July 11, 1994), a utility may not recover stranded costs if recovery is explicitly prohibited by the contract (including associated settlements) or by any power sales or transmission tariff on file with the Commission.

Third, for existing wholesale requirements contracts that do not address stranded costs through exit fee or other explicit stranded cost provisions, a public utility may seek recovery of stranded costs only as follows: (1) If the parties to the existing contract renegotiate the contract and file a mutually agreeable amendment dealing with stranded costs, and the Commission accepts or approves the amendment; (2) if either or both parties seeks an amendment to the existing contract under sections 205 or 206 of the FPA, before the contract expires, and the Commission accepts or approves an amendment permitting stranded cost recovery; or (3) if the public utility files a request, before the contract expires, to recover stranded costs through a departing generation customer's transmission rates under FPA sections 205–206 or 211–212.

Fourth, if the selling utility under an existing wholesale requirements contract is a transmitting utility but not also a public utility, and the contract does not address stranded costs through an explicit exit fee or other stranded cost provision, the transmitting utility may seek to recover stranded costs through a surcharge to a departing generation customer's transmission rates under FPA sections 211–212. Such utility may not seek recovery of stranded costs through a section 211–212 transmission rate if the existing requirements contract does contain an explicit exit fee or other stranded cost provision.

Fifth, for a retail-turned-wholesale customer, a public utility or transmitting utility may file a request to recover stranded costs from the newly-created wholesale customer through that customer's transmission rates under FPA sections 205–206 or 211–212.

Sixth, for customers who obtain retail wheeling, a public utility or transmitting utility may seek recovery through Commission-jurisdictional transmission rates only if the state regulatory authority had no authority under state law to address stranded costs when retail wheeling is required.

[900] ''Wholesale requirements contract'' is defined as ''a contract under which a public utility or transmitting utility provides *any portion* of a customer's bundled wholesale power requirements'' (emphasis added). Thus, a ''wholesale requirements customer'' for purposes of the Rule can be either a full or a partial requirements customer. We reject AMP-Ohio's suggestion that the Commission make a blanket finding that a utility could not have had a reasonable expectation of continuing to serve a partial requirements customer. For example, a partial requirements customer may have met part of its needs with its own generation but because it could not build more of its own generation locally it had to depend on the utility for the remainder of its needs in the absence of the new open access. Also, a partial requirements customer may have been able to reach alternative suppliers for only a portion of its requirements due to transmission constraints. If this were the case, the partial requirements supplier may well have had a reasonable expectation of continuing to serve the balance of the customer's load.

[901] The definition of ''retail stranded cost'' contains a similar requirement (*i.e.,* the retail customer must become, in whole or in part, an unbundled retail transmission services customer of the public utility or transmitting utility from which the customer previously received bundled retail services). We will retain it for the same reasons discussed above.

[902] As we have said, this Rule is not intended to insulate a utility from the normal risks of competition.

[903] As the Commission has previously indicated, however, in the case of formula rates, approval of a formula rate constitutes approval of the formula, and not the underlying costs. *See, e.g.,* New England Power Company, *et al.,* 72 FERC ¶61,148 at 61,761 (1995); Boston Edison Company, Opinion No. 376, 61 FERC ¶61,026 at 61,145 (1992).

K. Other

1. Information Reporting Requirements for Public Utilities

In the NOPR, the Commission did not propose any changes to its information filing requirements for public utilities.

Comments

Many IOUs argue that the current information filing requirements competitively disadvantage traditional public utilities and unfairly benefit sellers, such as power marketers, that are not required to provide comparable information.[904] They urge the Commission to eliminate the requirement for public disclosure of competitively sensitive, proprietary, or otherwise confidential Form No. 1 data. They contend that requiring such disclosure only from traditional public utilities harms such public utilities and compromises the development of efficient competition. Illinois Power asks the Commission to review all information that utilities must file, including EIA 860, EIA 767, and FERC Form No. 715.

A number of commenters believe that some type of information requirement must also be placed on non-public utility entities.[905] PacifiCorp suggests that the Commission should require transmitting utilities that do not file a Form No. 1 to file similar information annually with the Commission. Ohio Edison asserts that the Commission should extend its use of the reciprocity concept to require the filing of operating data with the Commission. Further, if non-public utility entities are not required to disclose certain information, Ohio Edison asserts that all public utilities that have received approval to sell power at market-based rates, including traditional utilities, should also be free from having to disclose such information.

Arizona argues that enforcing comparability vis-a-vis non-public utility transmitting utilities would seem to invite jurisdictional challenge. Thus, it would support legislation to broaden the Commission's jurisdiction.[906]

Commission Conclusion

We will not adopt the suggestion made by a number of commenters that we now eliminate the public disclosure of allegedly competitively sensitive, proprietary, or otherwise confidential data submitted to the Commission on Form No. 1, as well as on other Commission forms. The information that we collect from public utilities is necessary to carry out our jurisdictional responsibilities and is used, among other things, to evaluate the reasonableness of cost-based rates subject to our jurisdiction and the operation of power markets.[907] Moreover, as we explained in *ConEd*,

> [R]eports required to be submitted by Commission rule and necessary for the Commission's jurisdictional activities are considered public information. 18 CFR 388.106. In addition, the Commission has long required jurisdictional utilities to submit Form 1 data on a form that states on its cover that the Commission does not consider the material to be confidential.[908]

We are sensitive to the lack of symmetry in the generation information we require from traditional public utilities, particularly those that have market-based rate authority, and the generation information we require from other public utilities (*e.g.*, public utility marketers) authorized to sell at market-based rates.[909] However, the record in this proceeding is insufficiently developed for us to make and support a well-informed decision requiring a different reporting scheme, particularly given the industry's current rapid pace of change. Also, we are not persuaded that the burdens borne by traditional public utilities (primarily annual reports submitted months after-the-fact) are impairing the competitiveness of these utilities so much that we must act hastily now, instead of deferring a decision to a more appropriate proceeding. Moreover, we are required to regulate the rates of public utilities and, although we are moving toward greater reliance on market-based generation rates, we continue to regulate generation on a cost basis for most traditional public utilities, particularly rates for sales from existing generation. To assure that these rates are just and reasonable, we, as well as the customers of public utilities, need the more detailed information our regulations require public utilities to submit.

Accordingly, at this time, we will not change our information reporting requirements. As the industry becomes more competitive, we will monitor our reporting requirements to make sure that they are needed, fair to all segments of the industry, and consistent with the workings of a competitive environment.

2. Small Utilities

In the NOPR, we did not address whether special provisions were needed for small public utilities and small transmission customers because of the possible burden of unbundling, open access tariffs, and the OASIS requirement.

Comments

A number of commenters assert that the unbundling requirement poses significant problems for smaller public utilities and that small utilities should not be subject to the same requirements as larger utilities.[910] St. Joseph notes that in small utilities one system operator typically runs the system operations center. Functional unbundling, it asserts, would require the addition of another operator for each shift at great cost to the small utility. Central Hudson estimates that unbundling would result in an approximately 10 percent increase in the wholesale price, putting small utilities at a competitive disadvantage.

Several commenters assert that many small utilities enjoy little or no transmission market power because their systems tend to be in parallel with large systems and are bypassed as a result. They say that customers prefer to deal with one large regional utility rather than pay pancaked transmission rates for service through two or more small utilities.

Citizens Utilities argues that some systems are radial spurs of much larger systems and merely serve to link points of interconnection. It claims that a network tariff is not applicable in such a case and that it is unlikely that third parties would request service over such small or isolated systems. It recommends that if a utility is basically a spur system and faces little present or future demand for third-party service, the Commission should either relax the open access requirements or defer them until a section 211 request is submitted.

East Kentucky proposes that the Commission exempt not-for-profit utilities from the requirement to separate the functions related to operation and marketing, since small G&T cooperatives exist solely to serve the needs of their owner-member distribution cooperatives.

[904] *E.g.*, NIPSCO, Illinois Power, Centerior, Ohio Edison, EEI.

[905] *E.g.*, NSP, Ohio Edison.

[906] *See also* Minnesota P&L.

[907] *See, e.g.*, Consolidated Edison Company of New York, Inc. and Central Hudson Gas & Electric Corp., 72 FERC ¶ 61,184 at 61,891 (1995) (*ConEd*).

[908] 72 FERC at 61,891.

[909] We note that public utility marketers are required to file quarterly transaction reports so that the Commission can monitor the reasonableness of their charges and their ability to exercise market power. *See* Heartland Energy Services, Inc., 68 FERC ¶ 61,223 at 62,065–66 (1994). Unlike traditional public utilities, marketers do not use cost-based rates. Approval of the generation rates of non-jurisdictional transmitting utilities is not subject to our jurisdiction.

[910] *E.g.*, Central Hudson, Central Illinois Light, CVPSC, Citizens Utilities, East Kentucky, IPALCO, Montana-Dakota Utilities, Seattle, St. Joseph, Tallahassee, VT DPS.

VT DPS suggests that waiver of marketing and transmission personnel separation requirements may be appropriate in the case of smaller utilities that do not operate control areas. St. Joseph proposes that the Commission establish a threshold level based on system demand of 1000 MW, below which unbundling of wholesale transmission functions from other dispatching functions would not be required. Alternatively, St. Joseph proposes an exemption from unbundling where the utility can demonstrate that it has no market power and that unbundling would not materially improve the level of competition in the generating market.

Central Hudson believes that the Commission should allow the development of a short form tariff or else defer the functional unbundling requirement for smaller utilities and use the section 211 process in the interim to provide flexibility for these utilities.

Oregon Trail EC, a small rural electric, public utility cooperative, requests that the Commission revise proposed § 35.28 of its regulations to provide that the generic open access transmission requirements apply only to public utilities that *operate* facilities used for the transmission of electric energy in interstate commerce. It explains that it owns one transmission line that it leases to BPA, which operates the line as part of its integrated transmission network. Thus, Oregon Trail EC states that it cannot meet the requirements of the open access rule. It also points out that the Commission exempted Oregon Trail EC and other similarly situated utilities from the transmission reporting requirements of Form No. 715 because they did not engage in transmission planning.

ALCOA suggests that the default tariffs for smaller utilities with transmission systems unlikely to be used by others should not become effective automatically. Rather, the default tariffs should become effective only when service is requested. Citizens Utilities suggests that relaxed tariff requirements be established for small utilities with insignificant demand for transmission service.

BG&E believes that a utility using its system on a network basis for economic dispatch should not be required to file a network service tariff if there is no customer to take the service. It suggests that if municipalization were to occur, the Commission could then require the utility to file, within 60 days, a network service tariff to serve the new municipal.

Commission Conclusion

We are sympathetic to the array of concerns raised by small public utilities and small transmission customers. The regulations we are adopting include waiver provisions under which public utilities and transmission customers, and non-public utility entities seeking exemption from the reciprocity condition, may file requests for waivers from all or part of the Commission's regulations or for special treatment.[911] However, it is difficult to imagine any circumstance that would justify waiving the requirements of this Rule for any public utility that is also a control area operator.

We recognize, for example, that it might be a financial burden on small public utilities to unbundle generation from transmission, follow standards of conduct that separate transmission personnel from wholesale marketing personnel, and maintain an OASIS. These requirements may be particularly burdensome for small public utilities that own no generation and buy at wholesale on a radial transmission line from another utility's grid. In addition, if a small public utility's service territory is part of another utility's control area, the small public utility should be permitted to make a showing that it should be exempt from all or some of the Rule. In this circumstance, we will consider granting a waiver if the utility can show that: (1) It does not own transmission facilities, (2) it has turned control of its facilities over to someone else (such as the control area operator) who complies with the rule as its agent, or (3) no one is likely to ask to use its facilities (*e.g.*, because they are radial lines), and it commits to file an open access tariff within 60 days of a request to use its facilities and to comply with the rule in all other ways.

Because the possible scenarios under which small entities may seek waivers from the Final Rule are diverse, they are not susceptible to resolution on a generic basis and we will require applications and fact-specific determinations in each instance. We note here that any waivers that we may grant depend upon the facts presented in each case. If the circumstances that give rise to the exemption change, the waiver may no longer be appropriate. For example, a radial line today could very easily become part of a network tomorrow and a portion of a grid that no one is interested in using today could become an important transmission link tomorrow, especially if retail access is allowed.

In addition, we will apply the same standards to any entity seeking a waiver. This includes public utilities seeking waiver of some or all of the requirements of the rule, as well as non-public utilities seeking waiver of the reciprocity provisions contained in the pro forma open access tariff. Thus, we would not apply the open access reciprocity provision to small non-public utilities that are not control area operators and either do not own or control transmission or have transmission that no one is likely to ask to use. They would not have to provide an open access tariff, establish an OASIS, or separate operators of transmission from wholesale purchasers in order to satisfy the reciprocity condition for obtaining transmission service. However, they will have to apply for this waiver and demonstrate that they qualify for the waiver.

3. Regional Transmission Groups

In the NOPR, we again expressed our support for the voluntary formation of regional transmission groups (RTGs).[912] We also explained that the potential benefits of RTGs would not be undermined by the rules proposed in the NOPR.

a. Incentives for RTGs to Form and Resolve Regional Transmission Issues

Comments

A number of commenters urge the Commission to provide incentives for the formation of RTGs within two years of the adoption of the final rule.[913] Several commenters argue that the Commission should encourage a regional approach to transmission issues by expanding the role of RTGs.[914] Com Ed also claims that contract path pricing problems probably will need to be resolved at the regional level.

Sierra Pacific Power, which views open access as the major benefit of RTGs, questions the need to provide incentives for the development of RTGs once open access is implemented. However, it does see that RTGs may help promote open access with non-public utility entities, who have shown

[911] Non-public utility entities could request that the Commission find that they can satisfy the reciprocity condition without meeting all or some of the requirements that public utilities must meet. The requests could encompass a wide variety of circumstances. For example, a non-public utility could agree to offer comparable transmission services but not wish to have an OASIS or separate transmission personnel from wholesale marketing personnel due to the cost of doing so. The Commission could find that the entity nevertheless satisfied the reciprocity condition.

[912] FERC Stats. & Regs. ¶ 32,514 at 33,095.

[913] *E.g.*, AMP-Ohio, Missouri Joint Commission, MT Com, WEPCO, Nebraska Public Power District, Texas-New Mexico.

[914] *E.g.*, WEPCO, Portland, WA Com.

an increased interest in joining RTGs. American Wind and MT Com request that the Commission adopt policies that will encourage a close working relationship between RTGs and state authorities.

Otter Tail contends that the final Rule should stop short of establishing any conditions on the formation, governance, or functions of RTGs, arguing that such issues are complex and outside the scope of the NOPR. ALCOA and Missouri Joint Commission encourage the Commission to make certain that its policy regarding RTGs is not implemented in a manner that conflicts with the new open access regime.

Commission Conclusion

We continue to support the development of RTGs and encourage the formation of regional tariffs.[915] In our Policy Statement Regarding Regional Transmission Groups, we first explained our support for such voluntary associations.[916] We again explained our support in the NOPR:

> We believe that RTGs can speed the development of competitive markets, increase the efficiency of the operation of transmission systems, provide a framework for coordination of regional planning of the system and reduce the administrative burden on the Commission and on members of RTGs by providing for voluntary resolution of disputes.[917]

To further encourage the development of RTGs, we will accept regional open access transmission tariffs developed by RTGs that are consistent with the objectives of this Rule. This should make it easier for all parties in a region to coordinate their activities.

b. Deference to RTGs To Develop Regional Tariffs and Prices

Comments

A number of commenters urge the Commission to give considerable deference to RTGs on such issues as the formulation of pricing methods and RTG member duties.[918] Nebraska Public Power District requests that the Commission consider permitting a megawatt-mile pricing mechanism for MAPP. NWRTA urges the Commission to define clearly how much deference it will accord to RTGs and explicitly grant deference to RTGs on such matters as dispute resolution and decisionmaking processes. It also asks that the Commission honor the reciprocity provisions related to Canadian participation that are contained in the NWRTA agreement. Nevada Power requests the Commission to accept, as not unduly discriminatory, RTG open access tariffs that reflect the members' specific terms and conditions so long as the tariffs satisfy the substantive requirements of the final rule. It proposes that such tariffs be allowed to become effective without hearing or refund obligation.

Texas-New Mexico, while encouraging deference to RTGs in general, argues that deference must be conditioned upon a requirement that the RTG provide not only equal access but also terms and conditions of service that are comparable to what a customer could otherwise obtain under the final Rule tariff or under section 211 of the FPA.

Southwest TDU Group contends that RTGs should not be given deference, and RTG filings should be subject to the same standards and scrutiny as non-RTG filings.

Commission Conclusion

As we explained in the RTG Policy Statement, we intend to give deference to the planning, dispute resolution, and decisionmaking processes of an RTG. With respect to pricing proposals submitted by RTGs, we believe that RTGs may be able to develop solutions to such problems as loop flows through innovative flow-based pricing methodologies. As we stated in the Transmission Pricing Policy Statement, we will afford considerable deference to an RTG.

4. Pacific Northwest

Comments

Commenters in the Pacific Northwest ask the Commission to be flexible in reviewing tariffs that are based on regional practices, and that differ from the final Rule tariff as a result. Public Generating Pool urges the Commission to recognize that the Northwest's transmission system has been developed and is operated to support the region's coordinated power system. That is, it wants all hydro spill to be treated equally with no preference between federal and non-federal power. Also, it asserts that firm available transmission capacity in the Northwest must be worked out by the NWRTA RTG to account for the contingent operation of generation to avoid hydro spill.

Similarly, other commenters note that the Northwest's integrated transmission system was constructed to support a unique regionwide hydroelectric-dependent generating system and that flexibility is needed to accommodate the characteristics of the system.

WA Com argues that imposition of a uniform national tariff would not reflect the region's specific system characteristics or operating practices. It argues that the final Rule could impede rather than promote efficient competition in the Northwest. It believes that the Commission should defer to RTGs for defining and implementing wholesale transmission access terms and conditions at the regional level.

The Washington and Oregon Energy Offices, while supporting the adoption of regional practices, argues that uniform transmission principles should apply for all transmitting entities in the region. They argue that dispatch decisions are complicated by flood control, salmon passage, navigation, irrigation, and other constraints. Puget requests that the Commission give each transmitting utility the flexibility to file tariffs that fit unique or unusual circumstances and allow for regional market differences.

Because the terms and conditions offered by the smaller transmission owners in the Northwest are determined by the terms and conditions offered by Bonneville, Pacific Northwest Coop argues that the terms and conditions for wholesale power transmission, ancillary services, and RINs should be deferred until BPA's 1996 rate case is resolved and until appropriate regional and national systems and protocols are developed.

Commission Conclusion

As we explained with respect to RTGs, we encourage the filing of regional open access transmission tariffs.[919] The Final Rule pro forma tariff contains provisions allowing utilities to modify tariff terms to reflect prevailing regional practices. This should permit entities in the Pacific Northwest to address unique circumstances that exist in the Pacific Northwest and to incorporate prevailing regional practices (*e.g.*, treatment of hydropower generation in the priority of dispatch) into their open access transmission tariffs.[920] This should also encourage

[915] If an RTG is not a corporate person, each utility member of the RTG may file the same or complementary tariffs.

[916] 58 FR 41626 (August 5, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,976 (RTG Policy Statement).

[917] FERC Stats. & Regs. ¶ 32,514 at 33,095.

[918] *E.g.*, UT Com, ID Com, LA DWP, Nebraska Public Power District, Salt River, Nevada Power. *See also* NEPCO, United Illuminating, Utility Working Group.

[919] Also, as we explained with respect to RTGs, we will review pricing proposals in regional tariffs pursuant to our Transmission Pricing Policy Statement.

[920] This Rule will not resolve disputes over federal hydro preference policies or over the agreements incorporated in the Northwest Power Planning Act.

other regional solutions, such as the development of regional ISOs, to transmission problems.

In addition, although we will put the Final Rule pro forma tariff (which already allow for certain provisions consistent with regional practices) into effect for all public utilities 60 days after publication of this Rule in the Federal Register, utilities may file regional tariffs or propose deviations in the pro forma tariff based on additional regional needs to be effective at any time thereafter. Such proposals, however, will have to be consistent with the requirements of the Final Rule and be reasonable, generally accepted in the region and consistently adhered to by the transmission provider. Further, we will not permit entities in a region to claim different sets of prevailing regional practices.

5. Power Marketing Agencies

a. Bonneville Power Administration (BPA)

Comments

Washington Water Power explains that for open access transmission to be fully realized in the Pacific Northwest there must be federal legislation to remove the monopoly protections of federally generated power. Until then, Washington Water Power suggests certain mitigating measures that would increase competition in the Pacific Northwest. It also urges the Commission to take BPA's special characteristics into account in issuing the final rule.

Public Power Council encourages the Commission to make broad use of section 211 to mandate transmission access to ensure that BPA continues to provide comparable open access transmission.[921]

Public Generating Pool argues that the extent to which BPA's tariffs are allowed to deviate from the rule should be governed by the technical characteristics of the system and not by BPA's status.[922]

Direct Service Industries argues that the non-discrimination standard is made applicable to BPA by section 212(i) and that the Commission has the authority to review all BPA rates under the Northwest Power Act (citing Pacific Northwest Electric Power Planning and Conservation Act, section 7(a), 16 U.S.C. 839e(a)). It also argues that functional unbundling is particularly important for BPA because of BPA's market power and relative freedom from regulation. Clark also argues that the Commission should require BPA to meet the comparability standard. It alleges that BPA refuses to provide comparable service. It asserts that the Commission has authority to remedy the problem under the Energy Policy Act amendments to section 212, which Clark states gives the Commission authority over BPA's transmission practices. Clark also notes that BPA is a member of WRTA and, as such, must provide comparable service.

Pacific Northwest Coop argues that many of the issues presented in this rulemaking are currently being contested in the BPA rate case in Docket Nos. WP–96/TR–96 and TC–96. It says that the Commission should defer application of the rule to Pacific Northwest Coop and all of BPA's customers until conclusion of the rate case.

Washington and Oregon Energy Offices asserts that it would be proper for the Commission ''to impose similar transmission price structures upon Bonneville under section 211 orders as it will for jurisdictional [public] utilities under sections 205, 206, and the NOPR.''

With respect to stranded costs, BPA notes that it may be necessary to tailor a stranded cost policy for BPA that addresses the goals of open access and wholesale stranded cost recovery in a manner consistent with BPA's unique circumstances. BPA asks the Commission to defer consideration of its stranded investment and related cost recovery issues until it makes a rate filing with the Commission.[923] It further argues that the rule should not address whether and how BPA stranded costs might be recovered in transmission rates approved by the Commission under authority other than sections 211 and 212. Clark argues that the Commission's stranded cost recovery policy is inapplicable to BPA.

NW Conservation Act Coalition makes the following suggestions: (1) The Commission should grant BPA the authority to levy exit fees on customers who are terminating service and who do not use BPA's transmission system for their new power transaction; (2) any affected person should be allowed to petition the Commission for review of BPA's rates for inadequate or inappropriate mitigation of its stranded benefits; (3) the rule should insist upon a requirement that open access and stranded cost recovery be permitted only if the entities involved can show there will be no lessening of support for public purposes; and (4) the Commission should clarify that the Direct Service Industries customers are retail customers and that they will be subject to recovery of stranded costs and benefits.

Commission Conclusion

BPA is not a public utility under section 201(e) of the FPA and, thus, is not subject to the requirements of this Rule to put the Final Rule pro forma tariff into effect. However, there are three circumstances under which the Commission may review BPA's transmission access and pricing policies. First, BPA could file an open access tariff and accompanying rates for review and confirmation under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[924] and at that time could ask the Commission to find that its tariff meets the Commission's open access policies. Second, BPA is a transmitting utility subject to a request for mandatory transmission services under section 211 of the FPA. Transmission required of BPA under section 211 would have to be consistent with the requirements imposed on BPA under its organic statutes, the Northwest Power Act, and the Federal Columbia River Transmission System Act.[925] Third, if BPA receives open access transmission from a public utility, it is subject to the reciprocity provision contained in the utility's Final Rule pro forma tariff. If BPA seeks to comply with the reciprocity provision, it could use the declaratory order procedures we have provided in this rule for non-public utility transmission providers. Finally, we note that BPA has agreed to provide open access as a member of two RTGs approved by this Commission.

With respect to stranded costs, BPA has asked us to clarify that the Stranded Cost Rule does not address whether and how BPA stranded costs might be recovered in transmission rates approved by the Commission under authority other than sections 211 and 212 of the FPA (namely, section 7 of the Northwest Power Act). We clarify that this rule addresses only stranded costs recovered by public utilities under the FPA and transmitting utilities (including BPA) that are subject to mandatory transmission requests under FPA section 211. It does not address stranded cost recovery by BPA under the Northwest Power Act.

[921] *See also* Puget, Portland, Reynolds.

[922] *See also* Public Power Council.

[923] *See also* Snohomish, NPPC, W&O, Public Power Council, Washington and Oregon Energy Offices, Direct Service Industries.

[924] 16 U.S.C. 839–839h.

[925] 16 U.S.C. 838–838j.

b. Other Power Marketing Agencies

Comments

SEPA requests that the final rule assure that SEPA can receive network transmission service when necessary. It also indicates that it has 58 customers that receive less than one MW of power, but that the NOPR pro forma point-to-point tariff contains a one MW minimum scheduling requirement. Thus, it requests that the final rule allow some flexibility with respect to this requirement so that it can carry forward its marketing program.

DOE notes that the Western Area and Southwestern Area Power Administrations have pledged to offer transmission services that are comparable to those required of public utilities to the extent not otherwise prohibited by law.

Commission Conclusion

Federal power marketing agencies (PMAs) are not public utilities as defined under section 201(e) of the FPA and, thus, are not required by this rule to file non-discriminatory open access transmission tariffs.[926] However, to the extent a PMA receives open access transmission service from a public utility, it is subject to the reciprocity provisions in the utility's pro forma tariff.[927] If a PMA seeks to comply with the reciprocity provision, it can file a proposed tariff and seek a declaratory ruling.

With respect to SEPA's concern that the proposed point-to-point tariff has a one MW minimum scheduling requirement, but many of its customers have loads of less than one MW, we clarify that the Final Rule pro forma tariff will allow SEPA to continue to schedule service for these customers. Under SEPA's current transmission arrangements, it is allowed to aggregate loads within a single control area that are less than one MW individually, but jointly are more than one MW, to meet the requirement at an interface. The revised language in the Final Rule tariff permits this practice to continue. We also clarify that SEPA, as a seller of power to multiple purchasers inside several control areas, is eligible to receive network service.

6. Tennessee Valley Authority

Comments

TVA is concerned that the final rule may place TVA at a disadvantage because its opportunities to participate in the electricity market outside the TVA area are so severely limited by statute. It explains that it is restricted from directly participating in the new competitive landscape except through limited power exchange opportunities with a few neighboring systems. It urges the Commission to recognize these circumstances in the final rule. TVA is also concerned that its regional customers may face stranded costs because its ability to mitigate those costs by making replacement sales to new customers is limited.

Commission Conclusion

TVA is not a public utility under section 201(e) of the FPA and, thus, is not required to file a non-discriminatory open access transmission tariff under this rule.[928]. However, if TVA receives open access transmission service from a public utility, it is subject to the reciprocity provision in the utility's pro forma tariff. If TVA seeks to comply with reciprocity, it may avail itself of the Commission's reciprocity safe harbor approach, through a declaratory ruling, if it is fearful that a public utility may deny it service simply on a claim that TVA's non-discriminatory open access tariff is not satisfactory.[929] The details of this safe harbor procedure are set forth in Section IV.G.4.f.

7. Hydroelectric Power

Comments

Non-Firm Transactions

ID Com believes that the NOPR unfairly discriminates against hydro-based utilities. It argues that utilities that rely heavily on hydropower need to engage in non-firm market transactions that depend on water levels; *e.g.,* during low water years, a utility must have access to the transmission system to make non-firm, off-system purchases. It asserts that the NOPR treats non-firm sales and purchases as subordinate to firm transactions and does not allow the utility to reserve capacity for its critical, but non-firm, transactions. ID Com also asserts that the NOPR would, in effect, strand the utility's investment in the production plant being used to generate power for the non-firm sales.

Idaho complains that the NOPR unfairly allows a customer to buy and reserve firm transmission rights surplus to its needs, but does not permit a utility to do the same. It explains that this problem is particularly acute for hydro utilities and argues that they must be allowed to reserve at tariff rates at least a portion of available transmission capacity for firm and non-firm wholesale transactions. In the alternative, Idaho asserts that the transmission owner should not be required to provide point-to-point service for transmission uses other than from demonstrated firm obligations.

Commission's Licensing Practices

National Hydropower argues that in light of the NOPR the Commission should reexamine the manner in which it exercises its FPA Part I authority with respect to (1) economic feasibility determinations, (2) section 10(a) findings, (3) determinations of section 10(j) recommendations, and (4) section 13. For example, it states that the NOPR suggests that all future electric resource selection decisions should be based exclusively on short-run marginal cost comparisons. Because, it asserts, hydroelectric power provides many public interest benefits not susceptible to precise quantification, the Commission should clarify how non-price factors are to be considered in a post-final rule wholesale electric marketplace.

Commission Conclusion

Non-Firm Transactions

As we explained above with respect to the Pacific Northwest, we will permit entities to incorporate prevailing regional practices (*e.g.,* treatment of hydropower generation in the priority of dispatch) into regional open access transmission tariffs. This should permit entities in a region to resolve concerns over the scheduling of non-firm hydropower. In addition, if a utility and its customers can agree on the scheduling of non-firm hydropower and the disruption of firm transactions, we would permit that resolution to be incorporated into the utility's tariff. Utilities are permitted to consider seasonal variations in hydropower availability in the determination of Available Transmission Capacity to be posted on the OASIS.

Commission's Licensing Practices

The issues raised by National Hydropower with respect to our

[926] PMAs, however, are transmitting utilities subject to requests for mandatory transmission services under section 211 of the FPA.

[927] *See* Section IV.G.4.f.

[928] TVA, however, is a transmitting utility subject to requests for mandatory transmission services under section 211 of the FPA.

[929] We recognize that sections 212(f)(1) and 212(j) of the FPA, as amended by the Energy Policy Act, limit the applicability of section 211 to TVA, but conclude that this limitation in no way affects our application of the reciprocity requirement to TVA. Limitations on TVA's authority to market power are not the product of this rule but rather of TVA's enabling legislation. Thus, it is for Congress to decide whether TVA should be permitted greater marketing authority. As noted in our earlier discussion of reciprocity, TVA is not being required to file an open access tariff. Rather it is being precluded from taking advantage of benefits available under this rule without providing comparable use of its system to others.

hydroelectric licensing practices are beyond the scope of this rulemaking. Indeed, National Hydropower has already raised its concerns in a petition to the Commission to revise our hydroelectric licensing procedures, filed on July 10, 1995. That is the proper proceeding in which to address our hydroelectric licensing practices.

8. Residential Customers

Comments

Several commenters are concerned that the rule may undermine the financial position of public utilities so that they will not be able to provide many of the programs that benefit low-income residents (*e.g.*, assistance to low-income and elderly consumers, weatherization and energy conservation programs, and payment of taxes that provide many city services).[930]

La Raza is concerned that the rule will permit large preferred customers to opt out of the regulated structure, leaving behind a smaller and less affluent base to support the long-term investments made under the previous regulatory environment.

Home Builders is concerned that utilities may compensate for reduced profits under the proposed rule by raising infrastructure charges and hookup fees for new homes, thus reducing new home sales.

State and City Supervised Housing for Equity in Electric Rates states that publicly supervised housing is uniquely qualified to obtain open access electricity from wholesale markets, and that the Commission should adopt policies that bring competitive benefits to residents of such housing.

Commission Conclusion

While some residential consumers may be apprehensive about the changes that this rule may have on the electric industry, we are convinced that the changes we are proposing for wholesale markets will benefit them. As wholesale transmission open access becomes a reality, residential consumers should reap the benefits of more competitive bulk power markets and associated lower costs. This rule does not require retail transmission access for retail customers of any size. Moreover, this rule does not require any changes in programs such as assistance to low-income and elderly consumers and weatherization and energy conservation. As discussed in Section IV.I, those programs are under the jurisdiction of the individual states, and will remain under their jurisdiction. Indeed, this rule contains several safeguards to maintain the ability of states to impose conditions on retail access, such as conditions that help to protect residential customers from becoming the residual payer of stranded costs.

V. Environmental Statement

This section reviews and adopts the final environmental impact statement (FEIS) prepared by the Commission staff in connection with this rule. It identifies the alternatives considered by the agency in reaching its decision; analyzes and considers whether and to what extent the chosen alternative—adoption of this rule—is likely to result in environmental harm; evaluates alternatives and suggestions for mitigating environmental harm from the rule, if any; and states the Commission's decision.

Summary

A. The Environmental Impact Statement

The Commission decided to prepare an environmental impact statement (EIS) evaluating the environmental consequences that could result from adoption of this rule. We did so largely in response to the claims of several commenters, including the Environmental Protection Agency (EPA), who charge that the rule will have significant adverse environmental effects.

Although a number of issues were raised, by far the most prominent concern arises from the theory that competitive market conditions created by the rule will provide an advantage to power suppliers who produce power from coal-fired facilities that are not subject to stringent environmental controls on nitrogen oxides (NO_X) emissions.[931] Under this theory, these facilities, located primarily in the Midwest and South, will, as a result of the rule, generate more power and emit more NO_X, which will contribute to ozone formation. The ozone could add to pollution both in those regions and more significantly in the Northeast, to which area such pollutants could be transported. Those who propound this theory argue that it is the responsibility of the Commission, using its authority under the Federal Power Act, to effect environmental controls that will mitigate what they predict will be significant increases in NO_X emissions associated with this rule.

The staff prepared an FEIS based upon computer modeling simulations of power generation patterns and NO_X emissions likely to occur as a result of the rule. Staff used widely accepted models for studying economic conditions in power markets and simulating emissions of NO_X and other pollutants. These models took into account a variety of different assumptions concerning significant factors such as coal and natural gas prices and other competitive conditions. These factors are critical because increased use of coal-fired generation tends to increase NO_X emissions, while increased use of gas-fired generation is environmentally more benign.

The examination in the FEIS of the environmental effects that are likely to result from implementing the rule is based on an analytic framework that was shaped by comments received in the scoping process and on the DEIS. The study was revised to reflect the frozen efficiency reference case assumptions requested by EPA and other commenters. This was done to ensure full disclosure of possible environmental impacts even though the Commission disagrees that use of these assumptions is appropriate.

It has been observed in the context of agency preparation of an environmental study that ''(t)he NEPA process involves an almost endless series of judgment calls.''[932] That is particularly true where, as here, the agency undertakes to examine the impacts of a proposed regulatory program. In designing an effective assessment of the environmental impacts of the rule, the Commission had to make a number of judgments as to the type and the scope of studies necessary to analyze the proposals sufficiently. Commenters also raised many issues related to the design of the study. For example, the Center for Clean Air Policy contends that the Commission should model a range of mitigation policies; the Missouri Department of Natural Resources contends that the impact of the rule on generation may be locally intense and that these effects should have been studied; and other commenters sought to have the Commission examine different database or modeling assumptions.

For these and similar matters we exercised our judgment as to the appropriate manner in which to treat the issue. For example, we determined not to model a range of mitigation

[930] *E.g.*, Urban League, Latin League, Black Mayors, Homelessness Alliance, National Women's Caucus, La Raza.

[931] References throughout the Environmental Statement are to emissions from the electric industry, and not to emissions from all sources.

[932] Coalition on Sensible Transportation, Inc. v. Dole, 826 F.2d 60, 66 (D.C. Cir. 1987). The Court added that ''[i]t is of course always possible to explore a subject more deeply and to discuss it more thoroughly. The line-drawing decisions necessitated by this fact of life are vested in the agencies, not the courts.'' *Id.*

policies because we did not find that the impacts of the rule require the Commission to adopt or implement a plan of mitigation. It would have been extremely difficult, if not impossible, to examine the many varied local impacts that could be expected across the Nation in response to the Rule. We made judgments as to the appropriate database and modeling assumptions to use—in some cases, those assumptions were shaped or changed by comments we received.

In short, many competing considerations came into play during the design of the complex analysis used to examine the environmental effects of the rule. We exercised our judgment, for example, based on consideration of whether matters are within the scope of the rule, the most appropriate way to study the effects of the proposal, and whether the issues raised were relevant to a consideration of the environmental effects of the rule. The Commission's response to issues raised by commenters is reflected in the response to comments set forth in Appendix J of the FEIS. We conclude that the FEIS reflects the appropriate consideration of these and many similar issues.

B. Major Issues

Some comments on the draft environmental impact statement (DEIS), as well as earlier comments in response to Commission scoping inquiries, raise two major areas of objection to the Commission's analysis. First, commenters claim that in determining what NO_X emission levels would be in the future with the adoption of the rule, the Commission did not compare the emissions levels associated with the rule against the appropriate base case. They argue that the Commission should have analyzed and compared the impacts of the rule to a ''no-action'' alternative that assumes that the Commission abandons all its open access policies, not just this rule. Some commenters, including EPA, go even further, suggesting that the Commission compare emission levels projected to result from the rule against a ''frozen efficiency'' case in which other major factors—factors that would increase industry efficiency independent of the Rule—do not occur. Such factors include adoption of pro-competitive state policies and actions by utilities to undertake mutually beneficial voluntary transactions that do not require the use of open access tariffs mandated under this rule. Commenters who advocate either a different ''no-action'' alternative or the frozen efficiency case expect that studies using those assumptions will show that the rule will cause significantly greater NO_X emissions than shown in the DEIS.[933]

Assuming these results, these commenters raise their second major area of concern, which is mitigating the presumed effects of the rule. These arguments vary somewhat but share a common theme: That the Commission has a responsibility, either as a legal or public policy matter, to mitigate what they expect to be the significant environmental impact associated with the rule. They suggest various mitigation schemes, including a FERC-administered NO_X emission allowance program along the lines of the sulfur dioxide (SO_2) program enacted by Congress and administered by the EPA under the Clean Air Act. Other proposals would have the Commission condition the right of a seller to use an open access tariff on certification that the source of the power sold is in compliance with (as yet undetermined) emissions limitations. Another proposal would have the Commission impose a charge on emissions to be paid by utilities to a fund established by the Commission. The added cost to the utilities would work to account for, or ''internalize'', the external costs of emissions.

Commenters advocating Commission-administered mitigation argue that the mechanisms under current law for regulating NO_X emissions are cumbersome and slow, and that the Commission should not (some argue, may not) go forward with the rule unless it puts in place environmental regulatory mechanisms that prevent further increases in NO_X emissions.

Various legal theories are advanced as a basis for Commission environmental regulation under the Federal Power Act. Some argue that the conditioning authority under the Federal Power Act is sufficient to enable us to fashion comprehensive controls on emissions from utility generators because there is a direct causal nexus between power trading (which we regulate) and generation (which we do not). Others argue that such authority lies in the use of our power to impose requirements on utilities ''in the public interest'', enhanced by the National Environmental Policy Act. Others argue that, in remedying undue discrimination, we must correct competitive advantages arising from Congressional decisions to exempt certain kinds of generation facilities from some Clean Air Act regulation.

[933] *See* Section V, Discussion, Subsection C.

C. Commission Conclusions

After reviewing the comments and the additional studies conducted by staff in response to the comments, the Commission adopts the findings in the FEIS.

First, the findings show that, without the rule, NO_X emissions are expected to decline until at least the year 2000. Thereafter, again without the rule, NO_X emissions are expected to increase steadily through the year 2010 (the end of the FEIS study period). The extent of the decrease and the increase will largely be determined by the relative prices of natural gas and coal, the two main fuels used to generate electric power in most regions.[934]

In reaching this conclusion, the FEIS used two ''base'' cases. In one (the ''High-Price-Differential Base Case''), natural gas was assumed to become substantially more expensive compared with coal than it is today. In the other (the ''Constant-Price-Differential Base Case''), natural gas was assumed to maintain essentially the same price relative to coal that has existed for the last ten years. The two cases describe the range of emissions due to fuel price uncertainty without the rule and demonstrate the overall trends of decreases until 2000 and increases thereafter.

Second, the FEIS finds that the rule will not in any significant respect affect these overall trends.

The potential impact of the rule was studied initially under two scenarios.[935] In one (the ''Competition-Favors-Gas Scenario''), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor natural gas as a fuel. In this scenario the effect of the rule is slightly beneficial. Total NO_X emissions are reduced overall by about two percent nationwide from the base cases. In the other (the ''Competition-Favors-Coal Scenario''), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor coal as a fuel. In this scenario the effect is again slight, showing approximately a one percent increase in NO_X emissions nationwide from the base cases. In both scenarios, however, the rule does not have an overall effect on NO_X emission trends.

Stated differently, under any case studied, with or without the rule, there will be an overall net decrease in NO_X

[934] Generally, a relative advantage for coal is likely to increase environmental impacts while a relative advantage for natural gas is likely to create modest environmental benefits.

[935] A third scenario considered improved conditions for the transmission system only. This scenario showed very small effects from the rule and is not addressed further here.

emissions through the year 2000.[936] Thereafter, NO_X emissions begin to increase. The rule does not materially affect either the decline prior to 2000 or the increase thereafter.

Based on these findings the Commission concludes that a comprehensive, Commission-imposed mitigation scheme to address the environmental consequences of the rule is not appropriate. If competition favors gas, the effects are beneficial and mitigation is unnecessary. If competitive conditions favor coal through the year 2010, and NO_X emissions increase slightly as a result of the rule, these minor effects would be effectively mitigated as a part of a comprehensive NO_X cap and trading allowance scheme developed by EPA in cooperation with the Ozone Transport Assessment Group (OTAG) and administered by EPA and state environmental regulators under the clearly established authority of the Clean Air Act.

Further, the Commission believes that staff has selected the appropriate ''no-action'' alternative. An alternative that requires the Commission to reverse all its other open access policies is simply not a ''no-action'' alternative. To the contrary, it would require decisive action running counter to the direction from the Congress in the Energy Policy Act and the needs of the marketplace and electricity consumers.

However, to ensure that the effects of the rule were analyzed fully, the FEIS did study a reference case based on the ''frozen efficiency'' case proffered by EPA and the Department of Energy (DOE).[937] Although, as described below, we believe this case to be highly unlikely, the results show that, even under this scenario, the impacts of the rule are not great and do not vary significantly from those projected by staff under the other assumptions.

In one case requested by EPA, staff studied a combination of assumptions most likely to show significant increases in emissions associated with the rule; the case included EPA's frozen efficiency scenario, coupled with the ''Competition-Favors-Coal'' assumptions. Other cases requested by EPA posit dramatic increases in transmission capacity (that we find highly unlikely). Even this combination of assumptions—geared to demonstrate the greatest impact the rule might have on increased NO_X emissions—produced little in the way of environmental consequences associated with the rule. Under these extreme (and unlikely) conditions, there would still be a net decrease in NO_X emissions until at least the year 2000, albeit a smaller decrease than in the base cases. Comparing projections of emissions for the same years, emissions would be higher than the base cases only by two percent in 2000 and three percent in 2005.[938] It is only in the year 2010, assuming these improbable scenarios, that NO_X emissions associated with the rule would be higher than the base case by even five percent.[939]

Based on these studies, including the EPA reference case, the Commission endorses the staff findings that the rule will affect air quality slightly, if at all, and that the environmental impacts are as likely to be beneficial as negative. This is true even under scenarios contrived to maximize emissions associated with the rule under circumstances that this Commission believes to be highly unlikely.

Importantly, this is also true in the near- to mid-term. Until the year 2010, even the worst case (the frozen efficiency case) produces results very similar to those produced using assumptions the Commission believes to be reasonable. In short, the rule will not produce an ''ozone cloud'' coming across the Appalachians to threaten the Northeast on the day the rule goes into effect. Assuming that any environmental impacts occur, they are years in the future and may well be beneficial. As a result, calls for Commission mitigation, and in particular for interim mitigation to ''fill the gap'' until programs under the Clean Air Act can be adopted, are unnecessary and disproportionate to the possible effects of the rule.

We also endorse the staff view that it is neither within our statutory authority nor appropriate as a matter of policy to fashion from the FPA a comprehensive clean air regulatory program to address NO_X emissions. As described below, we believe that the mitigation proposals proffered in comments exceed our statutory authority to regulate rates, terms and conditions of sales of electric energy and transmission of electric energy in interstate commerce. We are, in essence and by law, economic regulators. While we have an obligation under NEPA to take the environmental consequences of our actions into account in fashioning our decision—and we have done so—NEPA grants us no new regulatory powers. While NEPA extends our general obligation to engage in reasoned decisionmaking to include the consideration of possible environmental consequences of our actions, it compels no particular substantive result.

Though our conditioning authority under sections 205 and 206 of the FPA is broad, our actions under it are confined to the subject matter of our jurisdiction. That subject matter excludes the physical aspects of generation and transmission. Our actions must derive from and advance our statutory mandate to protect consumers by establishing utility rates and business practices that are just, reasonable, and not unduly discriminatory or preferential. These authorities, however broad they are with respect to economic matters, are not unbounded; they may not be used to ''fill in the gaps'' of regulatory programs that, by law, are not our own.

Moreover, even if it were possible to tease from the FPA some implicit authority to regulate NO_X emissions from utility generators, it is not feasible for this Commission to develop and implement such a program. The mitigation schemes presented in comments are filled with unknowns and complexities that are best resolved by those charged with administration of the Nation's environmental laws. In some cases, the mitigation schemes are based on a model of utility transactions that is fundamentally at odds with the purposes of the rule. For example, several proposals would require the Commission to establish whether emissions from certain units or systems contribute to ozone noncompliance elsewhere, perhaps hundreds of miles away. Other proposals would require the Commission to establish baseline standards for emissions; generating units with emissions above that level would be required to adopt mitigation measures. The technical difficulties associated with these proposals are evident on their face. While resolving these issues is necessary to establish an effective NO_X regulatory program, the Commission does not possess the requisite expertise to establish baseline NO_X emission levels and address the difficult technical and policy issues that are presented in regulating NO_X emissions. EPA is the agency with jurisdiction over and experience with such matters. Although efforts are underway to resolve these issues within the framework of the Clean Air Act, all air regulators agree that much work still needs to be done.

[936] These results are set forth graphically and in tabular form in the FEIS at pp. ES–3 and ES–13. They are also reproduced in Appendix H.

[937] Although DOE agreed with EPA's request that we analyze the frozen efficiency case as a reference case, DOE believes that the DEIS selected the appropriate base case. DOE also argues that the mitigation of any adverse consequences from the rule should be addressed by EPA under the Clean Air Act or by the Congress.

[938] FEIS Table 6–10 at p. 6–17.

[939] *Id.*

Other proposals would require the Commission to track generation that is used for wholesale versus retail sales. However, for example, use of holding company corporate structures, as well as emerging market structures, would make it extremely difficult, if not impossible to distinguish between retail and wholesale transactions. In addition, such measures are inconsistent with the goals of the rule (and the Energy Policy Act) to eliminate time-consuming, inefficient transaction-based approvals that impede open access and to promote entry of sellers into bulk power markets on a competitive basis.

Moreover, any such program implemented by this Commission could well undercut the existing regulatory scheme crafted by Congress under the Clean Air Act, as amended. In particular, we are being asked essentially to rework the legislative decisions made by Congress regarding certain coal-fired generators. Those decisions are at the heart of the 1990 Clean Air Act compromise. The only means Congress has made available for addressing these problems under current law are in the Clean Air Act. If these means prove insufficient to address the NO_X problem overall, the case for change must be presented to the Congress.

Although we have concluded that NO_X emissions problems are most effectively addressed by clean air regulations within the framework of the Clean Air Act, we do recognize that the question of NO_X emissions is a very important one. Our FEIS documents that, with or without this rule, NO_X emissions from all sources are expected to increase over time. This will present a significant environmental issue for the Northeast, which is already struggling to reach current NO_X reduction standards, as well as for other regions of the country that are being called on to participate in an inter-regional solution to the NO_X problem. As the EPA rightly recognizes, attempting to frame an appropriate solution with the tools currently available is a tough job. We therefore understand why those concerned would try to enlist this Commission in an effort to solve this problem with regulatory mechanisms other than those set out in the Clean Air Act. We also understand why even the prospect of exacerbating that problem would ignite the kind of controversy reflected in the comments to this rule, and why, in response, those who have gained Congressional exemptions from certain regulations wish not to have those benefits undermined. At the same time, we understand, and have great sympathy with, the many commenters who have suggested that the economic benefits of this rule to consumers should not be suppressed or delayed by this difficult, ongoing debate.

Our FEIS clearly demonstrates that this rule is not the appropriate vehicle for resolving this very important debate. We believe that our study makes a significant contribution nonetheless. We have added significantly to the understanding of the problem and have established a viable, current baseline for assessing future industry trends. This baseline should serve air regulators well in analyzing overall NO_X emissions in the future.[940] We have resolved some important questions about the role of open access and have established clearly the influence of energy prices on NO_X emissions in the future.

Our study also supports the view held by many commenters that the appropriate regulatory mechanisms for addressing the NO_X problem overall, including emissions from electric utility generating plants, is a NO_X emissions cap and allowance trading scheme along the lines of that developed by the Congress under the Clean Air Act for SO_2 emissions. As staff suggests, even if there are slight environmental impacts associated with the rule, they are better and more effectively addressed as a part of a comprehensive NO_X regulatory program. While Congress did not enact such a scheme for NO_X, it did, as described below, empower the EPA to establish such a program. The EPA is the only federal agency with clear authority and expertise to address this problem. It should do so.

The FEIS also identifies the importance of OTAG to the development of a fair and effective NO_X regulatory program. OTAG, which includes representatives from all affected states, is currently at work developing the analytic basis needed for a regional consensus solution to the NO_X problem. OTAG is also evaluating possible solutions, including an allowance trading scheme. We believe that OTAG's efforts are to be applauded, and we encourage the EPA and all interested parties to work with OTAG to address this issue of national concern.

[940] For example, the data we used to project future industry generation and fuel use update by several years the data relied upon by EPA in its Regulatory Impact Analysis used as a basis for its recently proposed NO_X rule, entitled ''Acid Rain Program; Nitrogen Oxides Emission Reduction Program.'' 61 FR 1442 (1996). We believe the data developed in the FEIS will make a useful contribution to EPA's effort.

Discussion

A. Compliance With NEPA Requirements

1. Background

The Commission issued a NOPR in this proceeding on March 29, 1995. In doing so, we concluded that promulgating the proposed Rule would not represent a major federal action having a significant adverse impact on the human environment and that the proposed Rule fell within the categorical exemption provided in the Commission's regulations for electric rate filings submitted by public utilities under sections 205 and 206 of the FPA.[941] Subsequently, the Commission determined that, despite the availability of the categorical exclusion, it would nonetheless prepare an environmental analysis. On July 12, 1995, the Commission directed staff to prepare an EIS to assess the environmental impacts of the proposed Rule. That notice requested comments on environmental issues and scheduled a scoping meeting for September 8, 1995.[942]

A Notice of Availability of the DEIS was published in the Federal Register on November 27, 1995.[943] The DEIS evaluated several potential alternatives and mitigation measures as summarized below.

A Notice of Availability of the FEIS was published in the Federal Register on April 19, 1996.[944]

2. General Requirements

Section 102 of NEPA, 42 U.S.C. 4332, requires that federal agencies prepare an EIS on proposals for major federal actions significantly affecting the quality of the human environment. The objective is to build into the agency decisionmaking process careful consideration of environmental aspects of proposed actions, including the evaluation of reasonable alternatives. Although we believe a categorical exclusion to be available,[945] the Commission has performed this EIS to ensure that this Rule is promulgated with the benefit of careful consideration of its environmental aspects.

3. Alternatives

The consideration an agency must give in an EIS to alternatives to its proposed action is bounded by a number of factors, including notions of feasibility, whether basic changes would

[941] 18 CFR 380.4(a)(15).

[942] 60 FR 36752 (1995).

[943] 60 FR 58304 (1995).

[944] 61 Fed.Reg. 17,296 (1996).

[945] *See* 40 CFR 1507.3 (1995); 18 CFR 380.4 (1995).

be required to the statutes and policies of other agencies, and the extent to which the proposal would result in significant impacts. The United States Supreme Court (Supreme Court or Court) stated what is required in an EIS with regard to alternatives in *Vermont Yankee Nuclear Power Corp.* v. *NRDC,* 435 U.S. 519, 551 (1978): ''(A)s should be obvious even upon a moment's reflection, the term 'alternatives' is not self-defining. To make an impact statement something more than an exercise in frivolous boilerplate the concept of alternatives must be bounded by some notion of feasibility.'' [946] In this regard, the Supreme Court quoted *Natural Resources Defense Council* v. *Morton,* 458 F.2d 827, 837–38 (D.C.Cir. 1972), with approval as follows:

There is reason for concluding that NEPA was not meant to require detailed discussion of the environmental effects of ''alternatives'' put forward in comments when those effects cannot be readily ascertained and the alternatives are deemed only remote and speculative possibilities, in view of basic changes required in statutes and policies of other agencies—making them available, if at all, only after protracted debate and litigation not meaningfully compatible with the time-frame of the needs to which the underlying proposal is addressed.

The Supreme Court went on to discuss the concept of ''feasibility'', stating that:

Common sense also teaches us that the ''detailed statement of alternatives'' cannot be found wanting simply because the agency failed to include every alternative device and thought conceivable by the mind of man. Time and resources are simply too limited to hold that an impact statement fails because the agency failed to ferret out every possible alternative, regardless of how uncommon or unknown that alternative may have been at the time the project was approved.[947]

Thus, an EIS must discuss the alternatives that are feasible and briefly discuss the reasons others were eliminated. There is no minimum number of alternatives that must be discussed.[948] An agency's consideration of alternatives is adequate if it considers an appropriate range of alternatives—it does not have to consider every available alternative.[949]

The range of alternatives that must be considered in the EIS need not extend beyond those reasonably related to the purposes of the project.[950] An agency is entitled to identify some parameters and criteria related to the proposal for generating alternatives to which it would devote serious consideration. Without such criteria, an agency could generate countless alternatives.[951] Alternatives that are unlikely to be implemented need not be considered, nor must an agency consider alternatives that are infeasible, ineffective, or inconsistent with basic policy objectives.[952] In this sense, central to evaluating practicable alternatives is the determination of a project's purpose.[953]

Furthermore, the range of alternatives that reasonably must be considered decreases as the environmental impact of a project becomes less and less substantial. If a proposal would have minimal environmental effect, the range of alternatives that must be considered is narrow. It would be an anomaly to require that an agency search for more environmentally sound alternatives to a project that it has determined will have no significant environmental effects.[954] Moreover, feasible alternatives may be rejected if they present unique problems or cause extraordinary costs and community disruption.[955]

As applied to the instant case, NEPA does not require the consideration of alternatives that are remote and speculative possibilities because they would require basic changes to statutes and policies. Therefore, alternatives that would require the Commission to ignore open access policies enacted by Congress in the Energy Policy Act and to assume such policies would not be pursued by the states are not feasible and need not be considered. Likewise, the Commission need not consider alternatives that are ineffective or inconsistent with basic policy objectives, or that would cause extraordinary costs and community disruption. Finally, because the rule would have minimal environmental effect, the range of alternatives that must be considered is narrow. We conclude that staff has examined the appropriate alternatives in the FEIS and correctly determined that promulgation of the rule represents the most appropriate action.

Certain commenters have argued that the alternative that calls for the Commission to abandon the policy of promoting transmission access is more appropriate for the no-action alternative than the no-action alternative selected by the staff.[956] We disagree. As discussed below, that contention is more properly an argument about the appropriate baseline to use in the FEIS. That debate has been resolved by the consideration of a reference case that includes a baseline which bounds the effects that those commenters seek to have analyzed.

4. Mitigation

To fulfill the requirements of NEPA with regard to mitigation, an agency must identify and evaluate the adverse environmental effects of the proposed action, in this case the rule. Having identified and evaluated adverse environmental effects, the agency is not constrained from then deciding that other values outweigh the environmental costs of the proposal.

The leading case interpreting this requirement is *Robertson* v. *Methow Valley Citizens Council,* 490 U.S. 332 (1989)(*Methow Valley*). There, the Court explained that:

Although these procedures (preparation and circulation of an EIS) are almost certain to affect the agency's substantive decision, it is now well settled that NEPA itself does not mandate particular results, but simply prescribes the necessary process. *If the adverse environmental effects of the proposed action are adequately identified and evaluated, the agency is not constrained by NEPA from deciding that other values outweigh the environmental costs* * * *. Other statutes may impose substantive environmental obligations on federal agencies, but NEPA merely prohibits uninformed—rather than unwise—agency action.[957]

The Court held that ''(t)o be sure, one important ingredient of an EIS is the discussion of steps that can be taken to mitigate adverse environmental consequences.'' [958] This is so because:

Implicit in NEPA's demand that an agency prepare a detailed statement on ''any adverse environmental effects which cannot be avoided should the proposal be implemented, 42 U.S.C. 4332(C)(ii), is an understanding that the EIS will discuss the extent to which adverse effects can be avoided. More generally, omission of a reasonably complete discussion of possible mitigation measures would undermine the ''action-forcing'' function of NEPA. Without such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects * * *.[959]

The Court acknowledged that:

There is a fundamental distinction, however, between a requirement that mitigation be

[946] Vermont Yankee, 435 U.S. at 551.

[947] *Id.*

[948] Laguna Greenbelt, Inc. v. DOT, 42 F.3d 517, 524–25 (9th Cir. 1994).

[949] Resources Limited, Inc. v. Robertson, 35 F.3d 1300, 1307 (9th Cir. 1993).

[950] *Id.*

[951] *Id.*

[952] *Id.*

[953] National Wildlife Federation v. Whistler, 27 F.3d 1341, 1345 (8th Cir. 1994).

[954] Missouri Mining, Inc. v. ICC, 33 F.3d 980, 984 (8th Cir. 1994).

[955] Communities, Inc. v. Busey, 956 F.2d 619, 627 (6th Cir.), *cert. denied,* 506 U.S. 953 (1992).

[956] *See* Section V, Discussion, Subsection B.2.

[957] Methow Valley, 490 U.S. at 350–51 (citations and footnote omitted) (emphasis added).

[958] *Id.* at 351 (footnote omitted).

[959] *Id.* at 351–52 (citation omitted).

discussed in sufficient detail to ensure that environmental consequences have been fairly evaluated, on the one hand, and a substantive requirement that a complete mitigation plan be actually formulated and adopted, on the other * * *. Even more significantly, it would be inconsistent with NEPA's reliance on procedural mechanisms—as opposed to substantive, result-based standards—to demand the presence of a fully developed plan that will mitigate environmental harm before an agency can act.[960].

The Court again stressed that ''(b)ecause NEPA imposes no substantive requirement that mitigation measures actually be taken, it should not be read to require agencies to obtain an assurance that third parties will implement particular measures.'' [961] Thus, the Court held that mitigation, including mitigation that other governmental bodies have jurisdiction to implement, must be discussed in sufficient detail to ensure that environmental consequences of a proposed action have been fairly evaluated. However, a complete mitigation plan need not be actually formulated or adopted.

The suggestion by various commenters that the Commission is required to adopt and implement a plan to mitigate the impacts of the rule is without legal or factual basis. Even if the effects of the rule were greater than the FEIS shows them to be, *Methow Valley* clearly establishes that, regardless of the impacts of the proposed action, the Commission is required only to understand the impacts of its actions. This compels us to consider and discuss mitigation; it does not require us to adopt and implement mitigation. This FEIS thoroughly examines mitigation of possible adverse environmental effects and concludes that sufficient mechanisms exist to address the impacts of the rule, if any.

5. Role of EPA

Section 309 of the Clean Air Act, 42 U.S.C. 7609, authorizes EPA to review and comment on environmental impact statements prepared by federal agencies. If the EPA Administrator determines that a proposed regulation is unsatisfactory from, among other things, the standpoint of environmental quality, she may refer the matter to the Council on Environmental Quality (CEQ).[962]

In this case, EPA has commented extensively on the DEIS. It sought changes to the staff's analysis, primarily to include the use of the frozen efficiency assumptions. The staff has fully complied with EPA's study requests even though it regards such assumptions as implausible, contrary to the Energy Policy Act and Commission policy, and at odds with industry trends and practical considerations affecting the industry.[963]

Although EPA may disagree with the environmental acceptability of an agency's proposal, the agency is charged with making the ultimate determination whether to implement a proposal; in making that decision, the agency is free to reject advice offered through the comment and referral process.[964] Objections on the part of EPA may give rise to a heightened obligation of the agency to explain clearly and in detail its reasons for proceeding in the face of those objections. This the Commission has done. It has thoroughly examined the impact of the assumptions advanced by EPA; that analysis is detailed in Chapter 6 of the FEIS.[965]

In summary, NEPA prescribes a process and not a result. What is critical is that environmental impacts of a proposed action be adequately identified and evaluated—an important component of this process is understanding the possible mitigation measures that are involved, including measures which may be beyond the jurisdiction of an agency to implement. This requirement does not translate, however, into a requirement that an EIS adopt a mitigation plan, particularly where, as here, the impacts of the rule are small and may be either positive or negative.

B. Analysis of Alternatives

The FEIS evaluated three alternatives to the rule including: (1) A no-action alternative which assumes that the rule is not adopted, but that existing statutory and regulatory policies remain in place; (2) a Commission decision to reverse existing policies and halt implementation of mandatory open access; and (3) a Commission decision to aggressively develop competitive power markets by mandating corporate reorganization or divestiture.

1. The No-Action Alternative

The principal alternative to the proposed action is for the Commission not to adopt the rule, but to continue its existing open access and stranded cost policies. In recent years, the Commission has required public utilities that merge or seek to acquire jurisdictional transmission facilities under section 203 of the FPA to file open access transmission tariffs. The Commission also has required public utilities to file open access transmission tariffs to mitigate market power and to ensure non-discrimination if they or their affiliates wish to sell power at market-based rates. In addition, the Commission processes case-by-case requests made by potential transmission users under section 211 of the Energy Policy Act for transmission service, and has allowed utilities to include stranded cost provisions in their open access transmission tariffs on a case-by-case basis.[966]

Actions taken pursuant to section 211, and pursuant to sections 203 and 205 in merger and market-based rate cases respectively, represent a case-by-case approach to establishing open access. By contrast, the rule would, in a single generic proceeding, require each jurisdictional public utility to file open access tariffs at the same time. The consumer benefits from the rule are expected to be $3.8 to $5.4 billion per year.[967]

Absent action on the rule, the Commission would continue on a case-by-case basis to require public utilities to file open access tariffs and provide case-specific service as necessary or appropriate. Sections 205 and 206 charge the Commission with ensuring that voluntary transmission tariffs are not unduly discriminatory. If the rule were not adopted, the Commission would continue to require that voluntary tariffs be upgraded to offer non-discriminatory open access transmission services pursuant to the Commission's current standards. The result of continuing the Commission's policies without the rule is that the Commission would effectuate a more open transmission grid than is present today, but in a patchwork manner and at a slower pace. Over some extended time period, many, but not necessarily

[960] *Id.* at 352–53 (citation and footnote omitted).

[961] *Id.* at 353 n .16.

[962] The process appropriate for CEQ referral of actions by an independent regulatory agency is not addressed here.

[963] For example, see the discussion on transmission constraints at Section V, Discussion, Subsection C.

[964] *See* Alaska v. Andrus, 580 F.2d 465 (D.C. Cir.), *vacated in part on other grounds sub nom.* Western Oil & Gas Ass'n v. Alaska, 439 U.S. 922 (1978).

[965] The Commission bears the ultimate responsibility for evaluating the environmental impacts of the rule. In doing so, it must consider EPA's comments, but is not bound by them. *See* Citizens Against Burlington, Inc. v. Busey, 938 F.2d 190, 201 (D.C.Cir.), *cert. denied,* 502 U.S. 994 (1991). In that case the Court held that:

Congress wants the EPA to participate when other agencies prepare environmental impact statements. *See* 42 U.S.C. 7609(a). The EPA participated here. But the (Federal Aviation Agency), not the EPA, bore the ultimate statutory responsibility for actually preparing the environmental impact statement, and under the rule of reason, a lead agency does not have to follow the EPA's comments slavishly—it just has to take them seriously. *See Alaska v. Andrus,* 580 F.2d at 474.

[966] *See* Section III.

[967] *See* Section I.

all, utilities would become subject to open access requirements.

The case-by-case approach to achieving open access now in use is slower and more costly, and thereby less desirable, than the generic approach set forth in the rule. Given the rapid changes facing the industry, and the opportunity for great consumer savings, the no-action alternative is not a reasonable alternative to the rule.

2. Abandon the Policy of Promoting Transmission Access

A second alternative is for the Commission to abandon its current policy and take no action whatsoever to foster transmission access. Under this alternative, the Commission would no longer require open access transmission as a condition of mergers and asset acquisitions under section 203 or requests for market-based pricing under section 205, and would no longer grant applications filed pursuant to section 211. Offers of transmission would become strictly voluntary.

This alternative is inconsistent with Congress' general intent in the Energy Policy Act to foster wholesale competition, and also with its specific intent in expanding section 211 to permit the Commission to require a transmission-owning utility to make its transmission system available to eligible users if to do so is in the public interest. This alternative is also inconsistent with the Commission's obligations under sections 205 and 206 to ensure that public utilities do not unduly discriminate in providing jurisdictional services. It is, therefore, not a reasonable alternative to the rule.

3. Corporate Reorganization/Divestiture Alternative

Under this alternative, the Commission would require public utilities either to divest control of their transmission assets or to reorganize their corporate structures to perform their transmission functions through a separate subsidiary, thereby segregating transmission from the rest of the utilities' operations. However, corporate reorganization or divestiture would have no effect on the operation of power plants, which are assumed to be dispatched on the basis of economic efficiencies. Thus, this alternative would lead to the same environmental impacts as the rule. That is, the environmental effects would be no different from those studied in the FEIS.

C. The Scope of the FEIS

The FEIS examines the environmental impacts that could result from implementing this rule. This analysis is undertaken against the background of the existing electric industry. The electric industry currently produces environmental impacts, and those impacts are certain to change over time as the industry responds to factors as varied as changes in demand for electricity, the price of fuels, changes in regulatory programs, technological developments, and changes in market structure.

The FEIS does not examine the environmental impact of electric generation that is required to meet generators' existing service requirements. Nor does it examine the environmental effects of the inter-utility power exchanges that have occurred in the industry for as long as utilities have been interconnected. Rather, the FEIS examines impacts of potential increases in generation and changes in patterns of generation that might result from implementation of the rule.

In creating an analytical construct to examine the impacts of the rule, the staff developed a set of cases that defined the framework for running the computer models utilized to examine the changes in types of power plants constructed in the future and changes in operating patterns of existing power plants, including changes in fuel mix.

First, staff characterized how electric power markets might evolve absent adoption and implementation of the rule by establishing baselines (i.e., base cases) to project the future impacts of the industry.[968] The relative prices of coal and natural gas are critical in establishing what is likely to happen in the future. Accordingly, a range of prices was developed to project the impacts of these factors. In the first baseline, the Constant-Price-Differential Base Case, coal and natural gas prices are assumed to maintain the same relative position they have maintained over the past ten years. In the second baseline, the High-Price-Differential Base Case, natural gas is assumed to become substantially more expensive compared with coal than it has been over the past 10 years. In all other respects, the assumptions underlying the two base cases are the same.

Because the purpose of the base cases is to describe the impacts of the electric industry if the Commission takes no action over and beyond continued implementation of existing policies, the baselines assume that the Commission continues the open access and stranded cost policies it has instituted in recent years.

Some commenters have challenged this aspect of the baselines used in the study. The gist of their argument is that the environmental impacts of these programs have not been evaluated and that the baselines therefore improperly take credit for impacts that have not yet occurred, thus understating the projected impacts of the rule. In general, these commenters argue that the second alternative considered by the staff represents the ''true'' no-action alternative.

At bottom, this debate is not about what constitutes the appropriate no-action alternative. Rather, it is a debate about what aspects of the electric industry should be taken into account when determining future environmental impacts of the industry against which to measure the impacts of the rule. The commenters urge the Commission to consider varying baselines, but in general they oppose inclusion in the base cases of the Commission's ongoing open access and stranded cost programs.

Some commenters not only urge that the Commission not take into account continued implementation of its open access and stranded cost programs, but that it go much farther and establish baselines (against which to examine the impacts of the rule) that do not reflect the impacts of a great many changes that are already taking place in the electric industry. This proposal would establish a baseline that does not take into account: (1) Current Commission transmission policy; (2) programs that states and industry players have adopted to improve industry efficiency; and (3) mutually beneficial transactions that electric companies enter into on a regular basis.

The use of these assumptions would fly in the face of long-standing industry trends which move in precisely the opposite direction. Utilities are reducing reserve margins, improving plant availabilities, and reducing barriers to transmission even without Commission action.[969] Many states are aggressively pursuing plant efficiency policies.[970] These trends are long-standing and are not attributable to the rule, or even to a broader Commission program of open access. These trends, projected into the future, form the basis for the conditions reflected in the FEIS base cases. These trends are fundamentally at odds with the assumptions some commenters wish the Commission to use to establish baselines.

[968] As discussed below, once baselines were established to portray what is likely to happen in the electric industry without the rule, the projected impacts of the rule were then determined against this background.

[969] FEIS Chapter 6.

[970] *Id.*

We conclude that the approach used by staff to develop the baselines used in the FEIS is appropriate. Abandoning current open access policies is unrealistic, contrary to Congressional intent, and at odds with pro-competition policies that are at the heart of the Commission's current regulatory mission. The selection of the appropriate methodology to establish the baselines used in the FEIS is clearly within the Commission's discretion and expertise.[971]

What the commenters challenging this assumption desire is additional study of the impacts of the rule. Specifically, they wish to test the rule against a different set of assumptions for the acknowledged purpose of attributing greater adverse environmental consequences to the rule. The regulations of the Council on Environmental Quality no longer contain a requirement to conduct a conjectural ''worst-case analysis.'' [972] NEPA requires an agency to adequately identify and evaluate the adverse environmental effects of a proposed action.[973] It does not require the agency to ignore the world as it exists.

Nonetheless, to respond to concerns about the baselines used in the DEIS with respect to key atmospheric emissions, the staff conducted sensitivity analyses to examine the outer boundaries of a range of cases requested by some commenters. This range of cases is called the ''frozen efficiency'' case. In essence, the frozen efficiency cases assume that no further open access of any kind occurs during the study period and that efficiency in the industry (for instance, power plant availability) remains frozen through the same period. The assumption that there is substantially more inter-regional transmission capacity than posited in the original analysis is separately examined in the base and rule cases.[974]

We must reiterate that the frozen efficiency case is far more restrictive in its assumptions than a true no-action case in which the Commission simply stops all efforts to promote open access. A true no-action case would closely resemble the FEIS base cases because much of the efficiency gain in that base case would occur even with no move toward open access.

As detailed in Chapter 6 of the FEIS, and as discussed below, even the frozen efficiency case demonstrates results that are essentially the same as those demonstrated by the base cases used by the staff. In the frozen efficiency worst case, when coal prices become considerably more attractive compared to gas prices, national NO_X emissions would be lower than in the base cases used by staff by only one percent (in 2000) to four percent (in 2010). If coal and natural gas prices remain at today's relative levels, the effects would be smaller—zero percent in 2000 to two percent lower in 2010. National CO_2 emissions would be between zero and two percent lower than in the base cases used by the staff over the same time frame.

D. Economic and Environmental Impacts of the Rule

The FEIS reports a quantitative estimate of approximately $3.8 billion to $5.4 billion in benefits per year of cost savings expected from competition under the rule. The FEIS also considers other, non-quantifiable benefits that can be expected from implementing the rule. These benefits include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. Further, the FEIS demonstrates to our satisfaction that the rule is likely to have little or no adverse environmental impact and that any impacts are as likely to be beneficial as harmful.

The issue most frequently raised by commenters involves air quality impacts, particularly the possible transport of NO_X emissions from upwind areas to airsheds in the Northeast and the resulting impacts on ozone non-attainment areas.

With regard to NO_X, the FEIS demonstrates that, as a result of clean air regulatory programs, NO_X emissions nationwide, with or without the rule, will decline through the year 2000, but begin to climb thereafter.[975] This basic trend remains the same in all cases examined in the FEIS. This is because the level of NO_X emissions in any given year depends primarily on one key uncertainty that is not related in any way to the rule—the relative price of natural gas and coal.[976] Lower prices for natural gas, relative to coal, lead to lower levels of NO_X emissions.

The FEIS also demonstrates that increases in access to transmission and efficiencies in electric power markets associated with the rule do not alter the expected trend of NO_X emissions, regardless of the relative price of natural gas and coal. Increased transmission access and industry efficiency facilitated by the rule may either decrease total emissions somewhat or increase them somewhat, depending on whether competitive conditions in the electric industry favor natural gas or coal. When competitive conditions favor natural gas, the effect of the rule is beneficial, reducing emissions somewhat. When competitive conditions favor coal, emissions increase by a small amount. Nevertheless, the overall trend of expected NO_X emissions retains its general shape.

In assessing the projected impacts of the electric industry absent adoption of the rule (*i.e.*, the base cases studied in the FEIS), the most important factor affecting changes in national NO_X emissions is the relative competitive position of coal and natural gas. The most important factor affecting the relative competitive positions of coal and natural gas is price.

National NO_X emissions from the electric industry were 5,844 thousand tons in 1993, the last year for which complete data is available. If relative gas

[971] *See, e.g.*, Sierra Club v. Marita, 46 F.3d 606, 621, 623 (7th Cir. 1995).

[972] Methow Valley, 490 U.S. at 354–55. The revised requirement, 40 CFR 1502.22, which pertains to incomplete or unavailable information, is inapplicable as well. The problem here is not incomplete or unavailable information, but rather which existing policies and events should be included in the analysis.

[973] 42 U.S.C. 4332.

[974] Several commenters, including EPA, are concerned that increases in transmission capacities resulting from open access might increase generation levels and thus air emissions. EPA is especially concerned with the expansion of transmission links between the midwest and east coast. The FEIS examines scenarios that increase transmission capacity substantially beyond current levels. This analysis finds that postulated increases do not affect emissions attributable to the rule. We believe increases considered in the FEIS far exceed any transmission capacity increases that might occur as a result of the rule. This is due in part to the fact that state-level siting issues, the principal barrier to major capacity increases in the transmission grid, are unaffected by the rule. The issues regarding enhancement of existing lines are more complex. Competition under open access will lead to improved efficiencies in generation. Transmission, on the other hand, will remain a regulated monopoly function. The rule will reduce barriers to access, but will not open the transmission system to direct competition. Thus, we believe that the competitive effects of the rule on transmission expansion will be relatively small.

EPA urges us to assume that transmission capacity is expanded by 40 percent compared to our base case. We do not believe this is likely to occur. The experience with one proposed new transmission line in the very area EPA focuses on demonstrates this difficulty. Duquesne Light filed an application with the Pennsylvania Public Utilities Commission to construct a new 500 Kv line across Pennsylvania to supply electricity to New Jersey. Within a few days of the filing of the application, over 3,000 individuals and groups filed complaints in opposition to the proposed line. ''Electricity Utility Week'' (November 4, 1991). A bill was proposed in the Pennsylvania Legislature to prevent construction of the line. Another bill was introduced in Congress to halt construction of new transmission lines throughout the U.S. for two years. Duquesne ultimately decided to withdraw its proposal and the line was not constructed. ''The Energy Daily'' (April 4, 1994).

[975] FEIS Figure ES–1 and Table ES–2, reproduced at Appendix H.

[976] *See, e.g.*, FEIS at ES–8.

and coal prices remain the same, for example, we project that national NO_X emissions will be 5,579 thousand tons in 2005 without adoption of the rule. If gas prices rise relative to coal prices, we project that NO_X emissions in 2005 will be 6,053 thousand tons without adoption of the rule. Stated another way, favorable coal prices are projected to result in NO_X emissions that are about three percent higher in 2000 to 10 percent higher in 2010 over the base case where gas is the favored fuel.

The effect of adopting the rule could be to raise or lower national emissions slightly compared to the effects projected in the base cases. Nationally, in 2005, we project that the Competition-Favors-Coal Scenario (with rising relative gas prices) would add one percent to NO_X emissions above the base case that favors coal. The Competition-Favors-Gas Scenario (with constant relative fuel prices) would lower emissions by two percent compared with the base case that favors gas.

Regional effects are generally similar. In 2005, in the East North Central region (a source of potential increased NO_X emissions that might affect the Northeast), the base cases project small increases in industry emissions (two percent). In that region in 2005, the rule may add as much as one percent to NO_X emissions compared to the relevant base case (the Competition-Favors-Coal Scenario) or reduce emissions compared to the relevant base case by as much as three percent (the Competition-Favors-Gas Scenario).

The EIS uses the UAM–V model to track the effects of projected NO_X emissions on downstream ozone levels during a severe weather period. This detailed air quality modeling shows no real difference in the Northeast between the base case favoring coal (the High-Price-Differential Base Case) and the Competition-Favors-Coal Scenario. Detailed local analysis shows slightly lower ozone concentrations in some locations and slightly higher concentrations in others. None of the differences adds to non-attainment levels projected in the relevant base case, and all fall within the noise levels of the model. That is, they are smaller than the uncertainties in the science underlying the model.

As discussed above, the Commission believes that the base cases used by staff in its analysis are the most realistic and, therefore, the most appropriate cases to consider the potential environmental impacts of the rule. However, as requested by the EPA, DOE, and certain other commenters, sensitivity analyses were conducted to examine the impacts on the results of the analysis if key assumptions are changed as requested by commenters. Presumably, comparing the projected impacts of the rule to the requested ''frozen efficiency'' case provides a measure of the greatest impacts that could possibly (albeit unrealistically) be expected from implementing the rule.[977]

As the FEIS discusses, even comparing projected NO_X emissions under the rule to the highly implausible frozen efficiency case, impacts attributable to the Rule are projected to be modest or non-existent. This holds true even when large (up to 40 percent) increases in transmission capacity are assumed to occur under the rule.[978] Moreover, adding coal-favoring assumptions—which would presumably increase emissions—about future competitive conditions in the electric industry to the implausible frozen efficiency assumptions, NO_X emissions are projected to increase very modestly until the year 2010 (by only two percent in 2000 and three percent in 2005). Even using this highly unlikely alternative to the rule, the analysis projects a net environmental benefit (although a very small one) if gas prices stay constant compared to coal prices.

Concern also has been expressed with regard to the need to mitigate CO_2, mercury, and fine particulate emissions, and with the impact of the rule on visibility. As with NO_X, the FEIS demonstrates that the rule is as likely to improve such emissions and visibility as it is to exacerbate them. In any event, the impact is expected to be small.

In sum, the Commission adopts the FEIS findings that:

- The relative price of coal and natural gas has a larger effect on NO_X emissions than any impacts from the proposed rule. Without the proposed rule, different fuel price assumptions are projected to lead to a 7 percent difference between the two base cases in nationwide NO_X emissions in 2005, with some regions affected more than others.
- The rule is projected to have only slight impacts on NO_X emissions, and the impacts are as likely to be beneficial as harmful. In 2005, if competitive conditions in the electric industry (for instance, heat rates) favor natural gas, the proposed rule is projected to decrease baseline NO_X emissions by 2 percent nationwide. If competitive conditions favor coal, the rule is projected to raise baseline NO_X emissions by 1 percent. Regional effects in both cases are generally similar. In short, any negative impacts that the rule might cause are a small fraction of the uncertainty inherent in fuel price projections.
- Even a substantial increase in transmission capacity (up to 40 percent on every transmission line in the country) would change emission estimates by very small amounts in all cases. In many cases, the changes would represent net environmental benefits.
- Even comparing projected emissions under the proposed rule to the highly implausible frozen efficiency case, impacts attributable to the rule are projected to be modest or non-existent. The staff believes this is an unreasonable comparison because the frozen efficiency assumptions ignore industry trends that the Commission is generally powerless to stop. In effect, they assume that the alternative to the proposed rule is (1) for the Commission to reverse current transmission policy, an action that is inconsistent with Congressional policies under EPAct, (2) for states to cease adopting programs to improve industry efficiency, and (3) for electric companies to cease entering mutually beneficial transactions. Even after adding coal-favoring assumptions about future competitive conditions in the electric industry to the implausible frozen efficiency assumptions, NO_X emissions are projected to increase only very modestly until 2010 (by only 2 percent in 2000 and 3 percent in 2005). Even using this highly unlikely alternative to the proposed rule, the analysis projects a net environmental benefit (although a very small one) if gas prices stay constant compared to coal prices. EPA indicates that it considers the lower gas price assumption to be ''the more likely of the base cases'' (DEIS comments, p. 35).[979]

E. Mitigation Analysis

An agency is required to consider mitigation if the proposed action will result in adverse environmental impacts.[980] The insistence of commenters that the Commission adopt and implement mitigation measures is based on significantly overstated assumptions regarding the contribution of the rule to existing environmental problems. The analysis presented in the FEIS establishes that these assumptions about the impact of the Rule are wrong. As stated in the FEIS,

The sensitivity analyses (*i.e.*, the frozen efficiency case requested by EPA, DOE and other commenters) do not support the argument that the proposed rule is likely to lead to large immediate impacts that require

[977] These assumptions include, and go substantially beyond, the ''no-action'' alternative advocated by EPA and others in positing a baseline that would tend to maximize the amount of NO_X emissions attributed to the rule. This is because under a frozen efficiency scenario *all* increases in power trading (and resulting NO_X emissions) would be attributed to the Rule. In fact, as described below, many of the efficiencies posited under the EPA assumptions are attributable to other factors and certain of the efficiencies (*e.g.*, 40 percent increase in transmission capacity) are wholly unrealistic.

[978] Some commenters assume that large increases in transmission capacity would result in a significant expansion in generation and thus increased emissions. In reality, the analysis present in Chapter 6 of the FEIS indicates that this is not the case.

[979] FEIS at ES–2.

[980] *See* Methow Valley, 490 U.S. at 348–53.

immediate mitigation. In fact, using the more reasonable EIS base cases, it is clear that the proposed rule is at least as likely, if not more likely, to benefit the environment as it is to have adverse environmental impacts. As a result, we believe it is not a responsible course of action to undertake efforts to mitigate speculative adverse environmental consequences that may well not materialize; such action could well have the opposite effect and delay the clear benefits the proposed rule will produce in order to address small, highly uncertain environmental impacts.[981]

Even if the rule were to result in adverse environmental impacts as a result of competitive conditions that favor the future use of coal, such impacts are not likely to occur until about the end of the time period examined in the FEIS. EPA in its comments on the DEIS stressed, based on views it formed prior to knowing the results of the frozen efficiency case, that the Commission should develop interim mitigation until EPA can implement a program of controls. EPA stated in its comments that it has authority to address ''some'' of the impacts it believed would result from the rule, but stated that it would take it considerable time to do so—up to 10 years. The results of the unrealistic worst case analysis demonstrate that adverse effects would not be expected to occur for approximately 10 years in any event. Thus, interim mitigation is not required; EPA will have sufficient time to develop under the Clean Air Act whatever mitigation plan it may deem necessary.

Although the staff concluded that mitigation was unnecessary given the results of its analysis, given the importance of this issue, it nonetheless examined in considerable detail measures, including those proposed by commenters, that could be taken to mitigate adverse environmental consequences of the rule if they were to occur. The FEIS focuses on NO_X emissions in particular given the importance assigned to this issue by commenters.

1. Mitigation Measures Under the Clean Air Act

As discussed in greater detail in the FEIS, the existence for many years of a significant ozone non-attainment problem in parts of the U.S. has led to the development of mechanisms to address this issue. In particular, Congress has established requirements in the Clean Air Act for regulating NO_X emissions. These requirements establish specific NO_X emission levels for certain types of boilers. As discussed below, the Commission is not authorized to alter those requirements as requested by certain commenters.

In the 1990 Amendments to the Clean Air Act, Congress enacted the Acid Rain Program to reduce annual SO_2 and NO_X emissions. For SO_2, Congress established a cap and trade program that uses a market-based allowance system to reduce SO_2 emissions from utilities by approximately 50 percent. The allowance system caps utility emissions at 8.9 million tons a year by 2000. A pool of 8.9 million allowances was then created, each representing the right to emit one ton of SO_2 pollution in a specified calendar year. The allowances can be used to permit current emissions, sold, or held in reserve.

As a result of uncertainty in the understanding of ozone formation and transport, Congress acted less aggressively in regulating NO_X emissions. It chose to limit NO_X emissions from utilities by means of allowable emission limits and to require further study of ozone precursors, leaving room for the EPA to abate NO_X requirements where scientifically justified. Accordingly, in section 407 of the Clean Air Act, 42 U.S.C. 7651f, Congress established a NO_X reduction program which provides that EPA shall by regulation establish annual allowable emissions limitations for NO_X for specified types of utility boilers (Group 1 boilers). Section 407 also provides that, by not later than January 1, 1997, the Administrator shall establish allowable emission limitations for NO_X on a lb/MMBtu, annual average basis for specified other types of utility boilers (Group 2 boilers).

On April 13, 1995, EPA promulgated a Rule setting emission limitations on Group 1 boilers that combust coal as a primary fuel. EPA reports that the April 13, 1995 regulation ''is expected, by the year 2000, to nationally reduce NO_X emissions by an estimated 1.54 million tons per year.'' [982]

On January 19, 1996, EPA published a proposed rule to implement the second phase of the Acid Rain Program. This rule proposes to establish NO_X emission limitations for Group 2 boilers and to revise NO_X emission limitations for Group 1 boilers to impose tougher standards. EPA states that ''[t]he proposal would, by the year 2000, achieve an additional reduction of 820,000 tons of NO_X annually.'' [983]

In addition, Congress determined to deal with the issue of the interstate transport of ozone by authorizing the formation of transport commissions. The Clean Air Act authorizes EPA to establish transport regions that are charged with assessing the degree of interstate transport of pollutants, assessing mitigation strategies, and recommending revisions to State Implementation Plans to correct the problem. The Clean Air Act specifically establishes an ozone transport region (OTR) for the Northeast. The jurisdictions that comprise the OTR have developed a coordinated approach to this problem that includes adopting a regional cap on NO_X emissions.

Although the OTR process is achieving its purpose, a broader program is clearly appropriate to address the overall problem. As a consequence, the Ozone Transport Assessment Group (OTAG) has been formed which encompasses the OTR and upwind states that contribute to non-attainment. OTAG is performing extensive photochemical grid modeling of the eastern U.S. to determine ozone transport problems and to evaluate the efficiency of various control strategies. OTAG is considering recommending a cap and trade system for NO_X emissions from all sources in a 37-state area comprising the Northeast OTR and upwind states. If the cap and trading system becomes effective it therefore should fully mitigate NO_X emission increases, if any, attributable to open access transmission within the 37-state area. A cap and trade program is also likely to mitigate CO_2 and mercury emissions.[984] Any incremental increases in NO_X, mercury, or CO_2 emissions that may result from the rule can and should be addressed within this existing framework.

All of these factors lead us to agree with the staff's conclusion in the FEIS that a cap and trading system such as that under consideration in the OTAG process is the preferred approach to the overall NO_X emissions problem, including emissions associated with the rule, if any. This approach brings together EPA and the concerned states in a program that utilizes existing regulatory authority under the Clean Air Act.

The OTAG process brings to the table the parties that must participate in making the difficult decisions necessary to fully resolve this problem. OTAG possesses the technical resources and expertise to address the difficult scientific and technical issues that must be resolved to remedy this problem. A cap and trading system will require the

[981] FEIS at 7–5.

[982] 61 FR 1442 (1996).

[983] *Id.*

[984] It should be noted that the science relating to determining mercury emission levels and also to the environmental impacts of CO_2 is uncertain, particularly with regard to the impacts of CO_2 emissions. The FEIS evaluates these matters as best it can under the circumstances.

development of emission baselines for a great many entities; development of such baselines is certain to require extensive modeling and many difficult compromises. OTAG and others have been working towards this end for a long time. A more limited approach—one undertaken by this Commission or aimed at the limited (and only potential) impacts of the rule—cannot render a satisfactory solution. A program designed to deal with the slight impacts associated with the rule will not contribute significantly to the overall solution and could, indeed, impede it if the Commission took actions that prove inconsistent with solutions developed by OTAG or if debate over Commission-sponsored mitigation were to continue to distract interested parties from the preferred route of developing a consensus solution within the framework of the Clean Air Act. We respect the expertise and the goals of the OTAG process and do not believe we can or should substitute for them in addressing this long-term national problem.

2. Mitigation Measures Proposed by Commenters

The FEIS also analyzes NO_X mitigation measures proposed by commenters. These include voluntary measures pursuant to which the Commission would support utility efforts to mitigate pollution and proposals under which the Commission would mandate mitigation. Commenters suggest a variety of Commission actions including using its conditioning authority to require utilities to consider environmental impacts;[985] sanctioning imputed charges in rates to reflect incurred environmental externalities; and designing specific, transaction-oriented mechanisms designed to address the increment of emissions attributable to new wholesale transactions resulting from the rule.[986] The FEIS discusses five proposals in some detail: Those presented by the Center for Clean Air Policy (CCAP), the EPA, Joint Commenters, the Project for Sustainable FERC Energy Policy (Sustainable FERC), and the DOE.[987] Of these, the FEIS recommends the proposal put forward by DOE:

> Staff concurs (with the DOE analysis) that the best solution to the problem of NO_X transport and ozone non-attainment lies in exercise of statutory authority under the Clean Air Act by EPA and the states. Absent Congressional action, no resolution of the difficult political and technical issues will represent a lasting solution of this problem except one that comes from a collaborative process such as OTAG.[988]

As the FEIS explains in great detail, each of the other recommendations suffers from serious shortcomings. In one form or another, they would require the Commission to implement technically complex emissions control regimes outside of the Commission's expertise. Some would require that we duplicate existing monitoring systems. Others would require that we implement provisions that would, in effect, defeat the very purpose of the rule.[989] Indeed, these recommendations would have the Commission embark upon an extensive environmental regulatory regime that appears unwarranted, unworkable and, as discussed below in some detail, beyond our lawful authority. And they would have us act in a way that may well frustrate the ongoing efforts to deal with these problems and would frustrate the benefits to be derived from the rule.

The CCAP asserts that FERC should establish an emissions monitoring program for NO_X and CO_2 and implement an emission neutrality requirement (ENR) to mitigate what it believes to be the impacts of the rule. The monitoring program would require generators to identify emissions associated with off-system sales on a kWh basis in real-time and integrate this information with the data to be made available on electronic bulletin boards (EBBs). Under the ENR aspect of CCAP's proposal, to be eligible for service under open access tariffs, companies that operate plants upwind from the Northeast OTR and the upper Midwest would have to certify that firm and economy off-system power sales using an open access tariff would have no incremental impact on ozone compliance in other areas. All sales for resale that require service under an open access tariff and originate upwind of the OTR would need to include NO_X emissions reduction credits equal to the increase in emissions related to those sales. The seller could meet its requirement to be ''emission neutral'' under the mechanism by achieving the required emission reductions annually at their own facilities, or through purchases of credits anywhere in the airshed.

EPA proposes two mitigation alternatives. In the first, it states that FERC could deny open access service unless there is a showing that the service will not have an adverse environmental impact. Under this approach, EPA, in cooperation with the states in OTAG, would recommend and establish a mitigation mechanism that could be entered into by a customer seeking open access service and used by such customer to make the necessary environmental demonstration supporting the provision of the service. The FERC would rule on whether the mitigation mechanism presented by the customer and the evidence on the likely effectiveness of the mechanism were sufficient to make the environmental demonstration.

In the second proposal, EPA suggests that any fossil fuel-burning generating entity seeking service under open access transmission tariffs would be required to commit by an enforceable contractual undertaking that it will avoid or offset emission increases (measured against as yet undetermined baselines), and periodically certify its compliance with that commitment. Middlemen would have a similar obligation. The generator could meet its emission limits either by making verified emission reductions within its own facilities or by obtaining eligible emissions offsets from other entities. An important element of the mitigation mechanism is the emissions baseline above which mitigation would be required. This mitigation mechanism would operate until superseded by appropriate programs addressing these pollution problems under other authority. EPA's own comments on the DEIS recognize that there may be substantial practical complexities in implementing such mechanism.

The Joint Commenters propose a flexible mitigation strategy pursuant to which FERC would require as part of open access transmission a demonstration that NO_X emissions would not be increased. To qualify for open access transmission access, an electric generating unit would be

[985] For example, EPA suggests that we require certain types of filings, such as a request to charge market-based rates, to include an assessment of environmental impacts and mitigation, if necessary. Joint Commenters suggest we require wheeling and interconnection applicants to demonstrate that their requests will not contribute to increased NO_X or ozone in downwind regions, and Conservation Law suggests linking recovery of stranded costs to the retirement of unsuitable generators.

[986] The FEIS also discusses mitigation measures that can be undertaken by others. These include strategies to require some existing plants to meet more stringent, new NO_X standards, relying on market forces to control inter-regional NO_X transport, or measures that could be employed by the states to limit power purchases based on environmental considerations. *See* FEIS at 7–26 to 7–28.

[987] FEIS at 7–28 to 7–43.

[988] FEIS at 7–43.

[989] The rule represents the Commission's remedy to unduly discriminatory practices found to exist by public utilities that own and/or control interstate transmission facilities. Having found an unlawful practice, we must remedy it. However, EPA would require that those seeking to enjoy the benefits of non-discriminatory open access transmission further agree to go beyond current environmental requirements specified by federal and state authorities authorized by Congress to regulate such matters.

responsible for mitigating any excess NO_X emissions that adversely affect ozone non-attainment areas. Utility systems would be able to comply by use of emission control technology, fuel changes, or other measures to reduce applicable emissions, or by buying appropriate emission reduction credits to offset excess emissions. To comply with this policy, a company would need first to calculate whether it had excess emissions for the ozone season. A company that failed to mitigate would be required to remit to a regional emissions fund all revenues in excess of the incremental operating cost of producing electricity sold under the open transmission access policy during the previous ozone season plus an emissions make-up penalty the following year patterned after the penalty for excess emissions in the Acid Rain Program. The proposed mitigation policy would apply generally throughout the OTAG region.

The outlines of Sustainable FERC's proposal are vague, but it appears to request that FERC, either singly or in combination with other agencies, eliminate the different environmental standards that apply to entities participating in open access transmission. This plan would include the reporting of emissions data to EPA, principles to eliminate the adverse impacts of non-comparable environmental standards, and an EPA-administered emissions monitoring process designed to determine whether generating plant emissions of specific pollutants under open access exceed designated baselines.

Finally, DOE proposes action under the Clean Air Act as the most effective mitigation of the inter-regional NO_X transport problem. DOE supports the activities of OTAG and believes that a regional NO_X cap and trading system is a particularly promising approach. If OTAG does not succeed in addressing the problem, EPA should consider exercising its authority under sections 110 and 126 of the Clean Air Act, 42 U.S.C. 7410 and 7426, respectively, to require states to amend their State Implementation Plans to reach the same result.

The proposals advanced by CCAP, EPA, Sustainable FERC, and Joint Commenters suffer from practical and legal problems that render them unworkable. A common thread is for the Commission to ''level the environmental playing field.'' ''Impacts of non-comparable environmental standards'' are not impacts of this rule, but rather of the Clean Air Act regulations and statutory requirements under which those standards have been imposed. We have no authority to ''level'' the different emissions standards for different types of power plants, when those differences in standards are the direct result of the program adopted in the Clean Air Act and regulations promulgated by EPA. In enacting the Clean Air Act, Congress chose not to impose identical emission standards on all electric utility powerplants, but did create mechanisms for regulation of certain pollutants that can be used to ''level the playing field'' if that is appropriate clean air policy. For the Commission to presume to overturn those standards or seek to impose more stringent standards is something the Commission believes it cannot do.

A fundamental problem that plagues several proposals is the difficulty in identifying causation. While it is generally accepted that there is a link between increased emissions in certain areas of the country and increases in ozone levels in other areas, that link is in many respects poorly understood. In particular, it is difficult to prove that emissions from a particular unit or particular system contribute to ozone noncompliance elsewhere. As a result, it is very difficult to establish an analysis that would support a certification that a particular power sale would have no incremental impact on ozone compliance.

Similarly, the proposals tying ''emission neutrality'' to ''open access transactions'' seem to fundamentally misunderstand the operation of power markets and the role of open access tariffs in moving power from willing sellers to willing buyers. In particular, these proposals do not reflect the difficulty in identifying the transactions that are likely to result from the open access policies adopted in this rule. The rule does not authorize sales for resale of electric energy; rather, it establishes requirements for open access transmission, *i.e.*, it requires utilities with monopoly control of transmission to make transmission service available to customers who want to buy power from someone other than the transmission owner. Open access will facilitate transactions where the transmission owner will not provide service. However, generators do not necessarily have to request service under a Commission ordered open access tariff to make specific sales. There are a number of ways to structure transactions where third party transmission service is either not necessary or is voluntarily available.[990] Even when open access tariffs are used, the sales are not always (or even often) sales from specific generators to specific buyers. Marketers or brokers can buy generation from any number of sources. They can also buy transmission service in blocks that may not be associated with specific sales. Service agreements can be executed that allow use of non-firm transmission service for transactions that are not even known at the time of the execution of the agreement.

The rule envisions a world where transmission will be arranged with minimal transaction cost. Terms, conditions, rates, and even approvals often will be established far in advance of particular transactions. All other problems aside, requiring showings of the kind required by the various mitigation proposals would undermine the basic philosophy behind the rule, would make transactions much more difficult to engage in, would increase transaction costs, and would cause delays resulting in lost efficiencies. In addition, it would directly conflict with the Commission's responsibility under the FPA to remedy undue discrimination in jurisdictional services, which is the fundamental purpose of the rule.

Another significant issue with several of the proposals is how to establish the baselines against which to measure emissions. Establishing such baselines is extremely difficult; EPA itself, for example, has not come to grips with these complexities. The picture is complicated by difficulties in identifying open access transactions that result from the policies implemented by this rule. For example, some utilities use holding company corporate structures in which generation assets are held in an affiliate that sells power at wholesale to the holding company's distribution affiliate. For these utilities, all retail native load service would be subject to environmental review under the mitigation proposals if the base were established by reviewing all wholesale sales. This would make the Commission responsible for addressing all NO_X emissions from power plants for utilities with such corporate structures, a result that goes far beyond the stated goal of mitigating emissions that result from increased interstate trade facilitated by the rule.

As the industry changes, new structures are emerging that will make any system that tries to keep track of wholesale sales even more difficult to administer. California is putting into place an industry structure that could see all generation in the state sold into a central pool and then sold again at wholesale to distributors. Other states

[990] Indeed, over 100 utilities are now providing some form of open access on a voluntary basis.

are contemplating retail market structures that are even more fluid than the California proposal. Differentiating between sales for resale that are for former retail customers and sales for resale that are for ''new'' wholesale customers, and therefore somehow the result of open access policies, would be extremely difficult. In general, it is not easy to distinguish among growth in generation for native retail load, wholesale requirements customers, existing economy sales, and new sales that are facilitated by the rule, either for purposes of establishing a baseline or for tracking responsibility for emissions.[991]

Joint Commenters proposal would have the Commission impose a revenue collection measure—in essence a tax on open access transmission. The Commission is authorized by the FPA to pass through costs, not to collect additional fees from entities utilizing programs established by the Commission. The payment of emission fees is outside the Commission's authority under the FPA.

The FEIS concludes that mitigation by the Commission should not be undertaken in this rule because:

- Any mitigation measures the Commission might undertake are not justified by the small impacts of the rule, which impacts are as likely to be beneficial as they are to be harmful;
- The impacts of the proposed rule are dwarfed by the far larger ozone and NO_X emission issues that either have nothing to do with the electric industry or will be unchanged by the rule or the larger open access program. We believe that it would be ineffective to address the NO_X and ozone issues in a piecemeal way;
- The NO_X issue is part of a long-standing, difficult set of inter-regional environmental issues. Representatives of many interests have invested substantial efforts toward finding acceptable solutions through the OTAG process. Any mitigation the Commission might undertake could usurp EPA's mandate under the Clean Air Act and undermine progress towards comprehensive solutions sought by OTAG. This is not justified by impacts that are small and just as likely to be positive;
- We do not agree that the frozen efficiency reference case should be substituted for the EIS base cases or that competitive forces will favor coal over the next 15 years. But even accepting these assumptions, emissions attributable to the rule are relatively small until well after the turn of the century. So, even accepting such assumptions, the staff believes it would be unreasonable for the Commission to adopt mitigation requirements as part of the final rule; to do so would be tantamount to assuming that EPA and OTAG will not implement reasonable control measures in the next ten to 15 years;
- The Federal Power Act and NEPA, either singly or conjointly, do not authorize the Commission to adopt and implement the proposed mitigation measures. The Commission does not possess (and has no mandate to possess) expertise on the extremely difficult issues involved in atmospheric chemistry and transport. It is fundamentally an economic regulatory agency. As a result, any mitigation measures the Commission undertook would be based on less-than-ideal information and analysis. It is unreasonable for the Commission to attempt such mitigation given the impacts found in this FEIS. This is especially true in light of the substantial additional research that EPA and OTAG are undertaking on the basic nature of the problem;
- Some suggested mitigation measures that might work at the transaction level would undermine the purpose of the rule. There is no justification for endangering the substantial benefits projected from the rule to mitigate a problem that might not exist and that is, in any case, likely to be small.[992]

In sum, the rule is expected to have small impacts and those impacts are as likely to be beneficial as they are to be harmful. Therefore, mitigation is not required. In addition, processes are in place to address the pre-existing NO_X problem—a problem that dwarfs any impacts the Rule might have. These processes are expected to address the underlying transport problems well before any potential harmful effects of the rule will develop.[993]

The mitigation measures that certain commenters urge the Commission to adopt are truly unwarranted in light of these facts. They also fail to recognize or adequately consider the Commission's limited jurisdiction, its lack of expertise required to assess and address the underlying problem, the existing mechanisms and efforts to address the underlying problem, and the balance that has been reached and continues to be defined by the many interests that have invested substantial efforts toward finding acceptable solutions to these problems.

3. Legal and Policy Considerations

The FEIS concludes that the mitigation measures recommended by commenters are beyond our authority to implement and that strong policy considerations militate against their adoption. We agree.

Several commenters contend that the Commission is authorized to use the rulemaking as a vehicle to impose an air emissions regulatory regime on the electric utility industry.[994] Others argue that, as a matter of law and policy, we cannot and should not impose such measures.[995] While the conditioning proposals vary in specifics, all have as their central theme that generators would be forced to agree to operate generation facilities in a manner to reduce air pollution below levels currently authorized by EPA and the states.[996]

The Commission's authority to regulate public utilities is set out in Parts II and III of the FPA. Parts II and III do not provide the Commission with the authority to condition either the provision of, or access to, jurisdictional services on the agreement to undertake environmental mitigation measures.[997] Section 201, which is found in Part II of the FPA, explicitly bars the Commission from exercising the jurisdiction that the proponents of the conditioning

[991] We are also very concerned about the time and effort involved in developing the various programs suggested by commenters. The EPA and OTAG are working on the establishment of emissions standards, which action is an essential prerequisite to three of the proposals. However, developing those standards is among the challenges that EPA believes may take up to 10 years to complete. It simply makes no sense to delay the benefits of the rule (which has slight, if any, environmental impacts) during the period required for experts in the area to develop standards that, once established, can form the basis of a program under existing Clean Air Act authority.

[992] FEIS at 7–48.

[993] Many commenters state that the rule does not require mitigation and urge that a mitigation plan not be adopted. We would also note in light of the substantial number of comments opposing the proposition that we have mitigation authority, that any such mitigation measure we may choose to undertake would, in all likelihood, be subject to judicial review and the inevitable delays and uncertainties that accompany litigation. In the meantime, we would expect actions by OTAG and EPA to eclipse whatever action the Commission attempted to implement during this time.

[994] Alliance for Affordable Energy, *et al.* (Alliance); EPA; Project for Sustainable FERC Energy Policy (Project for Sustainable FERC); and Northeast States For Coordinated Air Use Management (NESCAUM).

[995] *See, e.g.*, AEP at 3; CINERGY at 8–9; Entergy at 11–13; GPU at 2; Midwest Ozone Group at 3; NMA at 5–8; Ohio Consumers' Counsel at 5; Ohio PUC at 1; TVA at 8; and WEPCO at 2. *See also* CCEM Supplemental Comments at 1–5.

[996] *See, e.g.*, CCAP (FERC should establish an emissions monitoring program and implement an emission neutrality requirement); EPA (either deny open access service unless the customer demonstrates no adverse environmental impact or require, through contract terms, any generating entity seeking open access service to avoid or offset emission increases for the benefit of third parties); Joint Commenters (electric generators to qualify for open access must be held responsible for mitigating any excess NO_X emissions through a revenue collection measure); Project for Sustainable FERC (pro forma tariffs to contain environmental mitigation measures imposed on generators). *See generally*, FEIS at 7–28 to 7–42.

[997] Parts II and III of the FPA originated with the Public Utility Act of 1935, 49 Stat. 803, 838 (Aug. 26, 1935) and stemmed in part from the financial abuses in the utility industry in the late 1920s and early 1930s. *See* Report of National Power Policy Committee on Public-Utility Holding Companies, S. Rep. No. 621, Appendix, 74th Cong., 1st Sess. 55–60 (1935); *see also* H.R. Rep. No. 1318, 74th Cong., 1st. Sess. 1–3 (1935). The FPA has been amended several times, most recently by the Energy Policy Act of 1992.

proposals would have us undertake: authority over the *operation* of generating facilities. Section 201(b)(1) provides that:

The Commission shall have jurisdiction over all facilities for (the transmission of electric energy in interstate commerce) or (the) sale of electric energy (at wholesale in interstate commerce), *but shall not have jurisdiction, except as specifically provided in (Parts II and III), over facilities used for the generation of electric energy* * * *. (emphasis added).

This standard is reflected throughout Parts II and III of the FPA. Sections 205 and 206, which are the cornerstones of Parts II and III, concern the regulation of *rates, terms and charges* occurring in connection with transmission or sales subject to the Commission's jurisdiction. Parts II and III do not grant the Commission authority to regulate the environmental aspects of jurisdictional activities.[998] Instead, they provide authority over certain interconnections;[999] the rates, terms and conditions of wholesale sales of electric energy in interstate commerce and transmission in interstate commerce; the disposition and merger of facilities used for such sales and transmission; issuance of securities; accounting matters; and interlocking directorates. Thus, the Commission's jurisdiction over generation extends only to matters directly related to the *economic* aspects of transactions resulting from such facilities.[1000] We do not have jurisdiction over the *physical* aspects of generation facilities.[1001]

This limitation on the Commission's jurisdiction stems from the historical purposes for which the Commission was established. Congress had two objectives in expanding the authority of the Federal Water Power Commission in 1935.[1002] The first was to close the gap created by *Public Utilities Commission* v. *Attleboro Steam & Electric Co.,* 273 U.S. 83 (1927)(*Attleboro*), in which the Court found that under the Commerce Clause states could not regulate wholesale sales of electricity in interstate commerce. The result was a gap in regulation of such sales because there was no federal entity with authority to regulate them at that time. The second was to eliminate the economic abuses that were then rampant in the industry.[1003] In expanding the Commission's jurisdiction Congress made clear that such Federal regulation, however, was ''to extend only to those matters which are not subject to regulation by the States.'' [1004]

Several commenters argue nonetheless that the Commission may do indirectly what it is barred from doing directly. Their arguments boil down to the claim that the Commission's responsibility under the FPA to act in the ''public interest'', either alone or in conjunction with NEPA, provides the Commission with the authority to impose environmental regulation on generators to address the supposed impacts of the Rule.[1005] We disagree. In making this argument, the commenters attribute to that standard a breadth of discretion that vastly exceeds the traditional ambit of our authority.

It is well established that NEPA merely establishes a procedural vehicle for assessing the impacts of a proposed action on the environment. It neither expands nor contracts the basic grant of jurisdiction made by Congress to the agency conducting the review, and it does not mandate particular results but simply prescribes a process.[1006] Commenters' arguments that NEPA somehow ''fills in the blanks'' of the FPA to authorize us to impose environmental regulatory regimes on generating facilities, or those who may purchase power from them, is simply incorrect. If we have such authority, it must be found in our substantive statute, the FPA.

Courts have addressed the breadth of our public interest standard on several occasions. The principal case on this point is *National Association for the Advancement of Colored People* v. *FPC* 520 F.2d 432 (D.C. Cir. 1975), *aff'd,* 425 U.S. 662 (1976) (*NAACP*). In *NAACP,* a number of organizations requested that the Commission promulgate regulations requiring equal employment opportunity and proscribing racial discrimination in the employment practices of public utilities.[1007] The Commission declined, finding that the FPA did not authorize it to do so. Petitioners appealed, contending that the Commission was authorized and required to act in the public interest:

to order such interconnections of electric power transmission facilities, setting such terms and conditions for the same, as are ''necessary or appropriate in the public interest''; to approve such asset sales and consolidations of interstate electric power companies as are ''consistent with the public interest; to approve such securities issuances by those companies as are ''compatible with the public interest'' and ''consistent with the proper performance * * * of service as a public utility''; to determine ''just and reasonable'' rates for interstate sales and transmission of electric power; and to order that ''proper, adequate or sufficient'' interstate power service be rendered.[1008]

On this basis, they argued that because prohibition of discrimination is in the ''public interest,'' the Commission was therefore required to proscribe discrimination by jurisdictional entities.

The Court rejected petitioners' argument. It observed that:

the (Federal Power) Act's preamble echoes the generality of the foregoing quoted

[998] The statutory framework established by Congress in sections 205 and 206 is not compatible with the administration of environmental regulatory regimes as a precondition to authorization. The Commission has only 60 days to review rate filings under section 205 before they become effective. Absent Commission action rejecting a rate filing or suspending its operation for up to five months within such period, a jurisdictional transaction (either the sale of energy or the transmission of energy) and the proposed rates accompanying the transaction go into effect by operation of law. Some mitigation proposals would require us to reject transactions within 60 days or allow them to go forward but with case-by-case determinations or hearings on environmental effects made within that time period. This could result in transaction gridlock for the trade of electricity in interstate commerce—a situation that is totally at odds with the regulatory framework established by Congress in the FPA and the Commission policy objectives under this rule to minimize regulatory impediments to fluid competitive power sales markets. Moreover, letting transactions go into effect subject to environmental hearings is not likely to produce meaningful environmental controls. Clearly, our processes, which contemplate the resolution of factual matters through hearings and the use of refund obligations to adjust parties' obligations on the basis of the record, make no provision for extensive scientific inquiry and are not designed to accommodate the imposition of clean air standards on power sellers.

[999] *See* FPA section 202(b), 16 U.S.C. 824c(b). *See also* Department of Energy Organization Act, 42 U.S.C. 7151, 7172.

[1000] We also note that section 731 of the Energy Policy Act preserves state and local authority over environmental protection and the siting of facilities.

[1001] For example, we do not have jurisdiction over the physical location of generation or transmission facilities, even though we have exclusive jurisdiction of the rates, terms and conditions of sales for resale or transmission of electric energy in interstate commerce by public utilities using such facilities, *i.e.,* the economic aspects of the use of such facilities.

[1002] The Federal Water Power Commission was established in 1920 with jurisdiction over the licensing of hydropower projects. 41 Stat. 1063 (June 10, 1920). In 1935, it was reconstituted as the Federal Power Commission, with expanded responsibilities over utility regulation. The jurisdiction over the licensing of hydropower was preserved as Part I of the Federal Power Act.

[1003] *See* Report of National Power Policy Committee on Public Utility Holding Companies.

[1004] FPA section 201(a), 16 U.S.C. 824(a). The House, Senate and Conference Reports concerning the Public Utility Act of 1935, *i.e.,* concerning Parts II and III of the FPA, are silent with respect to environmental concerns.

[1005] *See, e.g.,* comments by EPA, Project for Sustainable FERC, and Attorneys General.

[1006] *See, e.g.,* Methow Valley, 490 U.S. at 350–53; *see also,* LaFlamme v. FERC, 852 F.2d 389, 399 (9th Cir. 1988).

[1007] NAACP, 520 F.2d at 433.

[1008] *Id.* at 437–38 (footnotes omitted). The authorities listed cover FPA sections 202, 203, 204, 205, 206, and 207.

phrases, declaring that the sale and transmission of electric power are ''affected with the public interest,'' federal regulation of interstate aspects being ''necessary in the public interest.'' The statute itself nowhere defines the ''public interest,'' but instead leaves the precise ambit of the Commission's concern uncertain.[1009]

The Court found from the entirety of the Act that, ''(o)f the Commission's primary task there is no doubt, however, and that is to guard the consumer from exploitation by non-competitive electric power companies.'' [1010] The Court reiterated that ''(t)he Supreme Court has stated that the words 'public interest' do not constitute a 'mere general reference to the general welfare, without any standard to guide determinations.' '' [1011] Significantly, the Court also found that ''(w)ords like 'public interest' * * * though of wide generality, take their meaning from the substantive provisions and purposes of the Act.'' [1012] The Court concluded that:

Congress has not charged the Commission with advancing *all* public interests, but only the public's interest in having the particular mandates of the Commission carried out, its interest, in other words, in the conservation of natural resources and the enjoyment of cheap and plentiful electricity and natural gas. [1013]

With this, the Court rejected petitioners' argument that the FPA ''public interest'' standard requires the Commission to promulgate regulations prohibiting discriminatory practices by entities who are in some way regulated by the Commission. The Court found that the Commission was *not empowered* to promulgate anti-discrimination regulations because to do so would not be ''reasonably related to the furtherance of the Commission's proper objectives,'' which, under Part II of the FPA, are ''the enjoyment of cheap and plentiful electricity.'' [1014]

On review, the Supreme Court affirmed this limited reading of the Commission's authority to act in the public interest.[1015] In doing so, the Court noted that:

The use of the words ''public interest'' in the Gas and Power Acts is not a directive to the Commission to seek to eradicate discrimination, but, rather, is a charge to promote the orderly production of plentiful supplies of electric energy and natural gas at just and reasonable rates.[1016]

The question the Supreme Court asked in *NAACP* is the appropriate question here concerning the commenters' environmental mitigation proposals:

The question presented is not whether the elimination of discrimination from our society is an important national goal. It clearly is. The question is not whether Congress could authorize the Federal (Energy Regulatory) Commission to combat such discrimination. It clearly could. The question is simply whether and to what extent Congress did grant the Commission such authority.[1017]

We believe the same conclusion is true here for air pollution as the Court found there regarding discrimination.[1018]

The argument by EPA and others that because the FPA authorizes the Commission to act in the ''public interest'' it somehow authorizes the Commission to impose environmental mitigation measures is virtually indistinguishable from petitioners' argument in *NAACP*.[1019] Here, as in *NAACP*, parties urge the Commission to act to achieve worthwhile goals. However, the question is not whether the measures proposed by the parties would advance important national goals. Rather, ''[t]he question is simply whether or to what extent Congress did grant the Commission such authority.'' [1020] Also here, as in *NAACP*, the parties improperly base their belief that the Commission has authority to act under the FPA on an incorrect, overly broad application of the ''public interest'' standard. The goals sought to be advanced by EPA and others are broadly speaking ''in the public interest,'' but they are not goals that Congress has directed this Commission to pursue.[1021] Thus, just as the FPA did not authorize the Commission to take actions that petitioners requested in *NAACP*, the FPA does not authorize the Commission to undertake the types of environmental mitigation measures proposed by the commenters.[1022]

[1009] *Id.* at 438 (footnote omitted).

[1010] *Id.*

[1011] *Id.* at 440, *citing* New York Central Securities Co. v. United States, 287 U.S. 12, 24 (1932).

[1012] *Id., quoting* Alabama Electric Cooperative, Inc. v. SEC, 353 F.2d 905, 907 (1965), *cert. denied,* 383 U.S. 968 (1966).

[1013] *Id.* at 441 (emphasis in original). The Court made clear that ''the conservation of natural resources'' was a Commission interest only with regard to the regulation of hydropower resources under Part I of the FPA. *Id.* at 437.

[1014] *Id.* at 443 and 441.

[1015] NAACP, 425 U.S. 662 (1976).

[1016] *Id.* at 670 (footnote omitted). Several commenters, *e.g.*, Project for Sustainable FERC at 31–32 and Alliance at 53, make much of the Court's statement that there are undoubtedly other subsidiary purposes contained in the FPA and NGA, noting its reference in a footnote that the Commission has authority to consider ''environmental'' questions. NAACP, 425 U.S. at 670 n.6. However, they neglect to mention that the section of the FPA which the Court identified in support of this reference to environmental questions is section 10 of the FPA concerning our Part I authority over hydroelectric licensing matters, not Parts II and III. Part I contains explicit authority for the Commission to consider and require environmental mitigation measures.

[1017] NAACP, 425 U.S. at 665.

[1018] In analyzing the scope of the Commission's authority to act in the public interest, the *NAACP* Court found it useful to analogize to federal labor law. While noting that Congress had ''unmistakably defined the national interest in free collective bargaining,'' *Id.* at 671, the Court found that it could not be supposed that in directing the Commission to be guided by the ''public interest,'' Congress instructed the Commission ''to take original jurisdiction over the processing of charges of unfair labor practices on the part of its regulatees.'' *Id.* Yet this is exactly the form of what EPA and the other commenters supporting our authority to require environmental mitigation would have us do. However, just as with discriminatory employment practices, we can consider the consequences of air pollution practices of our regulatees ''only insofar as such consequences are *directly related* to the Commission's establishment of just and reasonable rates in the public interest.'' *Id.* (emphasis added).

[1019] We note that the standard the Commission is bound to apply in reviewing section 205 and section 206 transactions (which are the focus of the majority of commenters' mitigation proposals) is not a broad ''public interest'' standard, but rather a standard that rates, terms and conditions of such transactions be ''just, reasonable and not unduly discriminatory or preferential.'' 16 U.S.C. 824d, 824e.

[1020] NAACP, 425 U.S. at 665.

[1021] The limited nature of the Commission's ability under *NAACP* to consider ''environmental'' issues is reflected in the few court decisions on this subject. *See Public Utility Commission of California* v. FERC, 900 F.2d 269, 281 (D.C. Cir. 1990) (The broad public interest standards in the Commission's enabling legislation are limited to ''the purposes that Congress had in mind when it enacted this (NGA and FPA) legislation. This rule helps confine an agency's authorization ''to those areas in which the agency fairly may be said to have expertise.''); *Process Gas Consumers Group* v. *FERC*, 930 F.2d 926, 935 & n.14 (D.C. Cir. 1991) (Commission improperly allowed in rates the costs of research intended to benefit ratepayers solely through a ''cleaner environment''; the Court found that the Commission has no particular ''expertise'' in determining and promoting the pollution-reducing effects of natural gas vehicles).

[1022] The Supreme Court's holding in *NAACP* as to the limited ability of administrative agencies to implement broad ''public interest'' mandates, and direction to refrain from straying beyond the specific purposes of the regulatory legislation they are entrusted to administer, is well established. *See Community Television of Southern California* v. *Gottfried*, 459 U.S. 498, 510–11 n.17 (1983) (''[A]n agency's general duty to enforce the public interest does not require it to assume responsibility for enforcing legislation that is not directed at the agency''); *Hampton* v. *Mow Sun Wong*, 426 U.S. 88, 114 (1976) (''It is the business of the Civil Service Commission to adopt and enforce regulations which will best promote the efficiency of the federal civil service. That agency has no responsibility for foreign affairs, for treaty negotiations, for establishing immigration quotas or conditions of entry, or for naturalization policies''); *McLean Trucking Company* v. *United States*, 321 U.S. 67, 79 (1944) (that Congress ''has vested expert administrative bodies such as the Interstate Commerce Commission with broad discretion and has charged them with the duty to execute stated and specific statutory policies'' does not ''necessarily include either the duty or the authority to execute numerous other laws'' beyond enumerated statutory responsibilities); *see also Bob Jones University* v. *United States*, 461 U.S. 574, 611 (1983) (Powell, J., concurring) (''This Court often has expressed concern that the scope of an agency's authorization be limited to those areas in which the agency fairly may be said to have expertise'').

Lower courts have repeated the Court's admonition in this regard on numerous occasions

The Project for Sustainable FERC argues that in *Richmond Power & Light* v. *FERC*, 574 F.2d 610, 616–17 n.22 (D.C. Cir. 1978) (*Richmond Power*), the Court ''suggested'' a broader agency latitude than described in *NAACP*.[1023] We disagree.

Richmond Power involved a case where the Commission was challenged, *inter alia*, because it declined to adopt a particular transmission rate that would have permitted Richmond to shift from oil to some other fuel. The Court affirmed the Commission's decision, finding that:

> Although the Commission must serve the public interest in approving rates, we see no abuse of discretion in limiting this proceeding to the shortrun problem of setting just and reasonable rates for the service theretofore provided in response to the 1973 oil embargo. While an administrative agency must remain faithful to public policies directly related to its regulatory authority, surely at any given moment of history it may rationally decline to affirmatively foster other policies in weighing the specific interests that it is required by the statute to consider. This is especially true when the forum chosen by proponents of the other policy is not well suited to the study of its implications.[1024]

In dicta, in a footnote that began with the Court doubting whether the goal of energy independence is within the Commission's regulatory jurisdiction at all, the Court merely said that ''(n)othing in *NAACP* v. *FPC*, *supra*, forecloses agency discretion to *consider* in given situations pervasive public policies that it is not required to evaluate in every decision it makes.'' [1025]

The discretion to *consider* public policy matters is a far cry from the authority, or obligation, to regulate those matters. We have considered the environmental impact of the rule. Nothing in *Richmond Power* suggests that the consideration of such matters conveys an affirmative grant of broad new regulatory powers to develop and implement a comprehensive regulatory program in an area expressly assigned by Congress to another agency.[1026]

The cases rejecting commenters' broad reading of our public interest authority are supported by the decision in *Office of Consumers' Counsel* v. *FERC*, 655 F.2d 1132 (D.C. Cir. 1980) (*Great Plains*). There, the Court found that, even under the explicit ''public interest'' standard in section 7(a) of the Natural Gas Act, the Commission is not granted power to act on matters outside of its statutory mandate.[1027]

In *Great Plains*, the Court reviewed a Commission decision to grant a certificate of public convenience and necessity to facilitate construction and operation of a coal gasification plant. Although the NGA does not explicitly provide the Commission with authority to certificate coal gasification projects, the Commission reasoned that it had such authority because the demonstration project was ''in the public interest'' and, because the Commission was authorized under section 7 of the NGA to ''consider'' all factors in reaching a decision on whether to grant the certificate, it had the requisite authority to act.

The Court rejected the Commission's reasoning in that case, stating that:

> Any such authority to consider all factors bearing on the ''public interest'' must take into account what the ''public interest'' means in the context of the Natural Gas Act. FERC's authority to consider all factors bearing on the public interest when issuing certificates means authority to look into those factors which reasonably relate to the purposes for which FERC was given certification authority.[1028]

The Court repeated the finding in *NAACP* that the Commission's authority to act in the public interest is limited to the furtherance of the purposes for which its organic statutes were adopted.[1029]

In concluding that the Commission was not authorized to act as it did, the Court looked to several factors. The Court found it persuasive that Congress had specifically authorized a different governmental entity, the Synthetic Fuels Corporation, to provide support for coal gasification, and that Congress had carefully crafted a special means for providing federal financial assistance for synfuel development.[1030] The Court also found it persuasive that the Commission possessed no expertise in making determinations regarding the relative merits of different synfuel processes, methods or technologies, and that the financing arrangements ''were certainly not ordered with the interests of ratepayers foremost in mind.''[1031] The Court stated that ''by utilizing its statutory tools for a non-statutory purpose, FERC very likely was distracted from its primary statutory duty to protect the interests of ratepayers.'' [1032] Finally, the Court found that the Commission's action seemed to have been prompted at least in part by an attitude that, because Congress had not acted speedily, the Commission could act. The Court criticized the Commission for improperly attempting to preempt Congressional action and to ''fill in''

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in finding that federal agencies improperly have overstepped, or properly have refrained from overstepping, the limitations of their ''public interest'' (or similarly worded) jurisdiction. *See, e.g., The Business Roundtable* v. *Securities and Exchange Commission*, 905 F.2d 406, 413–14 (D.C. 1990) (SEC's assertion of authority under ''public interest'' standard to bar national security exchanges and associations from listing stock of certain corporations invaded traditional state regulatory purview); *Public Utility Commission of California* v. *FERC*, 900 F.2d 269, 281 (D.C. Cir. 1990) (FERC has no authority to consider allegations of copyright infringement or unfair trade practices in determining whether to issue certificates of public convenience and necessity); *American Trucking Association* v. *United States*, 642 F.2d 916 (5th Cir. 1981) (intention of ICC to promote competition is consistent with statutory standard; more generalized intention to promote public welfare needs, unrelated to its legislative instruction to attend to transportation needs of the public, is not); *Natural Resources Defense Council, Inc.* v. *Securities and Exchange Commission*, 606 F.2d 1031 (D.C. Cir. 1979) (SEC has no obligation to promulgate regulations requiring comprehensive disclosure of (among other things) corporate environmental policies unrelated to objectives of federal securities laws); *Sunflower Electric Cooperative, Inc.* v. *Kansas Power & Light Company*, 603 F.2d 791, 799 (D.C. Cir. 1979) (FERC does not have primary jurisdiction to consider antitrust-related issues that do not involve rate-setting practices of public utilities); *O-J Transport Company* v. *United States*, 536 F.2d 126, 131–32 (6th Cir.), *cert. denied*, 429 U.S. 960 (1976) (ICC properly did not stray beyond its congressionally-defined role over transportation regulation by refusing to promote more generalized public welfare concerns); *see also, e.g.*, In re Multidistrict Vehicle Air Pollution, 538 F.2d 231 (9th Cir. 1976) (under antitrust laws, federal district court has no authority to fashion an environmental remedy, intended to reduce auto emissions, that serves no antitrust purpose).

[1023] Project for Sustainable FERC at 31.

[1024] Richmond Power, 574 F.2d at 616–17 (footnotes omitted).

[1025] *Id.* at 616 n.22 (emphasis added).

[1026] Alliance and the Project for Sustainable FERC cite *American Trucking Association, Inc.* v. *United States*, 642 F.2d 916 (5th Cir. 1981), to support an argument that, even under *NAACP*, the Commission can impose conditions under the FPA ''public interest'' standard because there is a ''nexus'' between the primary goals of the FPA and the proffered conditions. As discussed below in greater detail, we disagree.

American Trucking involved review of an ICC rulemaking effort to, among other things, allow government agencies to tender a fair portion of their freight shipments to small businesses and those operated by disadvantaged persons. In reviewing the case, the Court referenced the *NAACP* decision to observe that under the governing law, the ICC's ''useful purpose'' and ''public need'' criterion (used here to justify the regulations) do ''not (refer) to the pursuit of affirmative action goals.'' *Id.* at 921–922. Indeed, it is clear that the Court read *NAACP* as permitting the consideration of ''racial, ethnic and social-economic factors'' only when they relate to the matters within the ICC's authority, *i.e.*, the transportation needs of the public, as opposed to some generalized notion of the general public welfare. *Id.* at 922 n.3.

[1027] NGA section 7(a), like, for example, FPA section 203(a), provides for a ''public interest'' standard of review. Section 7 of the NGA represents the maximum authority the Commission has over environmental issues under that Act. Section 7 provides the Commission authority to approve the siting and construction of facilities.

[1028] Great Plains, 655 F.2d at 1147.

[1029] *Id.*

[1030] *Id.* at 1150.

[1031] *Id.* at 1151.

[1032] *Id.*

where the agency believed federal action was needed.[1033]

The facts and reasoning in *Great Plains* are directly analogous to this proceeding. Congress has specifically authorized other entities—EPA and the states—under other statutes to address air pollution. The Commission is being urged to regulate in an area in which, as in *Great Plains,* it possesses no special expertise (*i.e.,* in making determinations regarding appropriate air pollution control mitigation measures) and in which it is not authorized to act.[1034] Finally, as in *Great Plains,* if the Commission were to undertake mitigation, it would be diverted from its primary statutory duty to protect the economic interests of ratepayers, *i.e.,* by having to continually monitor compliance with mitigation conditions.[1035]

As in *Great Plains,* the Commission is being urged to act at least in part because of the belief that Congress has not provided a sufficiently speedy process by which to regulate air pollution produced by electric utilities. The EPA argues that:

> Regulations under the Clean Air Act must in general be implemented through State Implementation Plans; the time from reaching a general conclusion that control is needed to adoption of necessary regulations by states generally takes from three to five years; that regulatory lag time means compliance with new rules can be, and usually is, more than a decade from the point at which the problem occurred. Ten years of bad air is ten years delay too many.[1036]

That Congress has imposed upon the EPA procedures that the EPA and others find burdensome and overly time consuming is an issue for Congress and EPA to address, not the Commission.[1037]

This conclusion has particular force when, as here, we are urged to impose environmental restrictions on certain coal-fired generators in spite of Congressional actions regulating those entities. In essence, some commenters argue that under a very tenuous connection to the public interest standard of the FPA we may undertake to do more than the agency that Congress has authorized to act on such matters. This result is not a correct reading of the law and we reject it.

Several commenters attempt to overcome the various Courts' views of the scope of the public interest standard under the FPA by arguing that there is a ''direct nexus'' between the Rule and environmental concerns that suffices to invoke an imputed authorization under the FPA to prescribe environmental requirements on generators.[1038] To this end, they argue that the purpose of the rule is really to facilitate the least-cost use and construction of generation resources and that the environmental consequences of these actions will impact economic efficiency, rates, competition, and competitive markets. Thus, they conclude that we have the authority to require that those who seek to obtain transmission access on a non-discriminatory basis must first mitigate air emissions under as yet undefined standards.

These commenters misstate the question. The question is not whether there is a nexus between the rule and environmental concerns. Clearly, electric utilities contribute to pollution; anything that facilitates the sale of power from whatever source is, under this tenuous logic, ''related'' to environmental concerns.[1039]

However, as discussed below, Congress did not give us plenary powers over public utilities to shape their activities in response to a broad range of public policy concerns. The nexus that must be established is a nexus between the requirements sought to be imposed, in this case emission controls, and the statutory *standards* which authorize us to act. That is, in order to impose the environmental conditions sought by commenters, a direct connection must be established between those conditions and our duty to determine that the rates, terms and conditions of service under our open access tariffs are not unjust, unreasonable, unduly discriminatory, or preferential.

It is on this point that commenters' arguments founder. While the Commission has broad latitude to interpret these standards to advance the interests of ratepayers, we cannot implement policy objectives that are not assigned to us and that are, in fact, clearly assigned to other entities. The Congress has assigned responsibility for environmental regulation of air quality to EPA and the states; it has explicitly charged them with dealing with such pollution from electric generating facilities. While, as noted earlier, we do not dispute the need to give appropriate weight to environmental considerations in making decisions within our authority, we cannot use that authority to accomplish public policy objectives that, by statute, are required to be implemented and administered by other agencies.[1040]

[1033] *Id.* at 1151–52.

[1034] To our knowledge the only time Congress has asked the Commission with respect to its regulation under Parts II and III of the FPA to address environmental issues was in Section 808 of the Clean Air Act Amendments of 1990. There, Congress directed the Commission, in consultation with EPA, to study the environmental externalities of electricity production. The Commission staff did so and provided the required report to Congress. While the Commission in compliance with the 1990 Amendments also addressed the accounting issues related to SO_2 emissions trading, the Commission did so within the context of its accounting authority under the FPA.

[1035] EPA argues that the Commission would not be required to monitor compliance with the environmental mitigation measures. However, if environmental mitigation is within our statutory mandate, we could not delegate that authority to others. *See* EPA at 51.

[1036] EPA at 4–5; *see also* Project for Sustainable FERC (protections achieved by the Clean Air Act Amendments of 1990 are in danger of being destroyed by the Energy Policy Act's open access policies if those policies are implemented without environmental mitigation).

We would also note that the premise upon which EPA makes this argument—that air emissions will rapidly increase with implementation of the rule—is not supported by the record. *See* Section V, Discussion, Subsection C.

[1037] We believe that this conclusion is supported by section 205(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA, *inter alia,* amended the FPA in certain respects but also gave the Commission authority in certain sections, such as PURPA sections 205(a) and 210, that did not amend the FPA. Under PURPA section 205(a), the Commission in certain circumstances may exempt electric utilities, in whole or in part, from state laws, rules or regulations which prohibit or prevent voluntary coordination, including agreements for central dispatch. (Of course, the central dispatch is dispatch of generation facilities.) However, PURPA section 205(a)(2) provides that no exemption may be granted if the state law, rule or regulation is designed, among others, to protect public health, safety or welfare *or the environment.* In commenting on the limitation of the Commission's exemption authority under PURPA section 205(a), the Conferees noted that the prohibition includes ''regulations under the Clean Air Act.'' H.R. Conf. Rep. No. 1750, 95th Cong., 2d Sess. 95 (1978), *reprinted in* 1978 U.S. Code Cong. & Ad. News 7797, 7829. While the Commission's statutory authority has been modified in legislation enacted subsequent to PURPA, the provisions of PURPA section 205(a) have not been modified.

[1038] *See, e.g.,* EPA at 54. *See also* Alliance; Project for Sustainable FERC; Coalition; Signatories; CCAP; Attorneys General.

[1039] Under this logic, the Securities and Exchange Commission, for example, which facilitates utility financing for new facilities would be empowered to administer environmental requirements.

[1040] We are also troubled by the confusion that persists as to the usefulness of imposing a condition on the use of open access tariffs as a means to accomplish environmental goals. As noted earlier, the Commission's decision to compel the filing of open access tariffs is intended to provide access to third party power suppliers who need access across a utility's transmission system. Open access will primarily benefit independent power suppliers offering power from new facilities, most of which under current market conditions are likely to be gas-fired facilities. Traditional utilities that own the generating plants of particular concern to commenters (*i.e.,* coal-fired plants subject to less strict environmental controls) have extensive transmission systems that they can use to get power to market. Thus, the exercise of conditioning authority is more likely to impede sales from new, cleaner facilities than it is sales from older, coal-fired facilities. It makes no sense from an economic or environmental perspective to burden new transactions with this cumbersome condition for what will likely be little in the way of effective environmental controls.

Some commenters have sought to address this issue by characterizing the proposed conditions as necessary to create a level competitive playing field among generators. For example, Alliance argues that unless the Commission requires environmental mitigation certain competitors in the bulk power market (those with ''dirty generation'') would be favored over ''clean'' competitors. It argues that:

> Mitigation of the environmental impacts resulting from the NOPR has a direct relationship to ensuring that open access is implemented under terms of economic fairness for all utilities and utility consumers, and not merely those with current low-cost regulatory advantages.[1041]

We note that all power generation technologies have different costs. For example, hydroelectric facilities which, like coal-fired facilities, may have environmental mitigation conditions imposed on them, may be quite expensive to build compared to gas or oil-fired generation, but their operating costs may be significantly lower. These cost differences may reflect the different costs of complying with mandated environmental requirements; the prudent costs of complying with such mandates may be reflected in rates.

Indeed, sellers come to the power markets with a variety of advantages and disadvantages, many of which are the result of federal laws—for example, tax preferences, labor standards, and similar matters. In empowering the Commission to remedy undue discrimination and promote competition, Congress has not authorized the Commission to equalize the environmental costs of electricity production in order to ensure ''economic fairness.'' Such homogenization of competitors, or their costs, has never been a goal of the FPA.[1042]

In short, the ''economic nexus'' urged by commenters advocating that the Commission undertake to regulate air emissions is inconsistent with the ''charge to promote the orderly production of plentiful supplies of electric energy'' envisioned by the FPA.[1043]

We have exercised conditioning authority in the past only where necessary to ensure that jurisdictional transactions and rates do not result in anti-competitive effects, or are not unjust, unreasonable or unduly discriminatory or preferential.[1044] Thus, the conditions we have imposed have involved economic regulatory matters within our purview under the FPA.[1045] Any exercise of conditioning authority must, as the Supreme Court noted in *NAACP*, be directly related to our economic regulation responsibilities; EPA and the other commenters have not demonstrated such a nexus.[1046]

This distinction is more evident when one considers the way in which we are authorized to treat the costs of environmental compliance. There are legitimate costs of environmental compliance that should be reflected in jurisdictional rates to the extent prudently incurred, just as the prudent costs of complying with, for example, occupational health and safety requirements designed to protect utility employees should be reflected in jurisdictional rates. This we are authorized to do and we routinely review and allow such costs.[1047] However, the fact that the costs of providing utility workers with a safe workplace are properly reflected in utilities' jurisdictional rates does not mean that we have authority to condition sellers' rates or customers' use of jurisdictional services on meeting safety regulations that are in the public interest. The same rationale applies to environmental matters related to the rule.[1048]

Commenters also raise several other arguments to support the claim that the Rule requires us to undertake environmental regulation to remedy supposed impacts of the rule. EPA, for example, argues that requiring environmental mitigation would not run afoul of the prescription of section 201(b)(1) of the FPA enjoining our regulation of generation facilities because the ''regulation of transmission tariffs necessarily has manifold indirect effects on generation sources. The proposed mitigation mechanism would influence generation sources in a similar, indirect manner.'' [1049]

EPA fundamentally misunderstands the purpose of the Rule. We act to remedy unduly discriminatory practices in, as here for example, the provision of transmission access. Since ''undue discrimination,'' is one of the matters ''specifically provided in this Part (II)'', *i.e.*, in FPA sections 205 and 206, we are acting within the bounds of our statutory mandate and the effect that the Rule may have ''over facilities used for the generation of electric energy'' is specifically sanctioned. Indeed, many generators are transmission customers who we are obliged to protect under the FPA. That there may be indirect environmental consequences from our Rule does not trigger our jurisdiction under the FPA.

[1041] Alliance at 55. *See also* Project for Sustainable FERC at 37.

[1042] For the same reason, we do not have authority to impose an obligation on utilities to ''internalize'' environmental externalities. *See generally* FEIS at 7–24. In effect, such proposals would involve the Commission requiring a surcharge on power sales rates fixed at some amount equal to the environmental ''cost'' inflicted by the generation supporting those sales. Assuming such a surcharge could be calculated, imposing such a cost would be to fix a rate without reference to any cost incurred by the public utility. Indeed, we would impose in rates, and require ratepayers to pay, a cost that was manifestly not incurred by the utility. In reality, such a surcharge would require us to impose a tax or a penalty, neither of which we are authorized to impose.

The SO_2 program created under the 1990 Clean Air Act Amendments illustrates the way in which EPA and FERC authority can intersect to accomplish the goal of internalizing externalities. There, the Congress by capping emissions and providing for a market in emission allowances required utilities to ''pay for'' the right to emit SO_2. These costs are legitimate costs and the *Commission's* role is to permit their recovery in rates. Similarly, a comparable NO_X cap and trading scheme established by EPA would ''internalize'' the external costs of NO_X pollution and the Commission would provide for prudently incurred allowance costs in rates.

[1043] NAACP, 425 U.S. at 670.

[1044] Cf. Utah Power & Light Co., Opinion No. 318, 45 FERC ¶ 61,095 at 61,280–83 (1988) (discussing the Commission's authority to condition a merger). Unlike the situation in Opinion No. 318 where the Commission had the authority under section 203 to disapprove a merger upon a finding of actual and potential anticompetitive effects, the Commission's rate authority under sections 205 and 206 does not permit the Commission to deny the proposed rates out of a concern that such action will result in an increase in air pollution. *See* Monongahela Power Co., 39 FERC ¶ 61,350 at 62,096, *reh'g denied,* 40 FERC ¶ 61,256 (1987). As a result, we have no authority to condition the same result under these sections on environmental mitigation.

[1045] The obligation of the Commission to weigh antitrust considerations highlights this point. The Commission must take into account anticompetitive effects when setting rates. *See Northern Natural Gas Co.* v. *FPC,* 399 F.2d 953 (D.C. Cir. 1968). However, we are limited as to the remedies we may impose. We cannot go further and assess the range of remedies that, for example, a Court may exact upon finding an antitrust violation. *See generally* NAACP, 520 F.2d at 441.

[1046] Project for Sustainable FERC, at 32–33, and Alliance, at 41–42, have attempted to argue that *NAACP* actually supports the Commission having authority to order environmental mitigation. Their argument fails because they have not shown, and cannot show, the necessary direct nexus to our economic regulation.

[1047] For example, our regulations permit 100 percent of any construction work in progress for pollution control facilities allocable to wholesale sales to be included in rate base. *See* 18 CFR 35.25 (1995). This regulatory action, directly related to our core ratemaking responsibilities, removes an economic disincentive for public utilities to invest in structures designed to reduce the amount of pollution produced by a generating facility. *See* 18 CFR 35.25(b) (definition of pollution control facility).

The Commission also addressed the ratemaking consequences of SO_2 emissions trading in response to a petition from the Edison Electric Institute. This is another example of the Commission's proper exercise of its jurisdiction, *i.e.*, over the costs of environmental compliance.

[1048] Indeed, our regulations provide for such cost recovery.

[1049] EPA at 50.

EPA next argues that, even if we could not impose a specific mitigation mechanism for open access transmission, we could deny transmission service unless there is a showing that the service will not have an adverse environmental impact.[1050]

We have already discussed why we believe this approach is unworkable and inconsistent with sections 205 and 206 of the FPA.[1051] Plainly stated, EPA would have transmission customers assume an additional regulatory burden in order to be treated lawfully.[1052] Quite apart from this fundamental problem, such a regime is beyond our authority. Our regulation under sections 205 and 206 is over the *selling* public utility's rates, terms and conditions, not over the buyer's agreement to undertake measures which have no nexus whatsoever with the seller's costs or terms of service.

EPA states that its alternative mitigation mechanism would not be a condition of the open access *tariff*, but apparently a condition on the ability of customers to take service under the tariff. However, our authority to set terms and conditions of eligibility derives from precisely the same authority that we use to set other tariff terms. It must still be based on a nexus with the subject matter of our jurisdiction. For buyers, open access is a right, not a privilege. We fail to see, given the direction of the FPA to ensure these rights, any basis for us to undertake the actions EPA proposes.

Finally, EPA points to the Commission's decision to exclude certain diesel facilities in defining qualifying facilities (QF) under PURPA section 210.[1053] However, this provides no precedent for imposing environmental standards to prevent customers from obtaining nondiscriminatory open access. Whatever the merits of that decision,[1054] the Commission subsequently found that any facility that satisfies the ownership and technical requirements for QF status set forth in PURPA and the Commission's regulations is a QF without any action by the Commission.[1055] More to the point, EPA ignores the fact that, in issuing environmental findings with its QF Rules, the Commission found that environmental concerns were a local matter to be handled under other statutory authorities. While PURPA permitted certain qualifying facilities to be exempt from state and federal laws,

> it excludes exemptions from environmental laws. Thus, a qualifying facility may not be built or operated unless it complies with all applicable local, State, and Federal zoning, air, water, and other environmental quality laws, and unless it obtains all required permits.[1056]

Thus, while we have noted that QFs are required to satisfy all environmental requirements, we have not viewed our responsibilities under PURPA as permitting us to enforce compliance with environmental laws.[1057]

EPA then proposes to require any fossil fuel-burning generating entity seeking service under an open access tariff to (a) commit by contract to avoid or offset emissions increases (measured against certain baselines), and (b) periodically certify its compliance with that commitment.[1058] This proposal is neither workable nor within our jurisdiction.

The deficiency with respect to (a) is that we have no authority to require such action. While EPA cites to FPA section 206 for the proposition that we may change jurisdictional contracts, we may do so only if the contract is, for example, unjust or unreasonable with respect to matters within our jurisdiction, *i.e.*, economic regulation. Our standards for acting are strictly prescribed under the FPA.[1059] As *NAACP* and *Great Plains* teach, sections 205 and 206 do not provide the Commission with the means to remedy every possible problem that is in any fashion related to a sale for resale or transmission in interstate commerce by a public utility. Since we do not have the authority to require (a), it follows we cannot require the periodic certification of compliance recommended in (b).

EPA notes that it ''could establish a procedure whereby a generator could *voluntarily* subject its facilities to emission limits that are enforceable by EPA and/or state environmental authorities.'' [1060] This is a matter within EPA's province, and we support EPA in undertaking whatever measures it determines to be within its authority and appropriate to the problem.

Alliance argues, at 47–51, that sections 211 and 212 of the FPA, as amended by the Energy Policy Act, authorize the Commission to impose environmental conditions. To the extent that Alliance's arguments rely on the ''public interest'' language used in section 211, we believe that the discussion above already addresses such arguments, with one exception: Alliance argues that the House Report for the Energy Policy Act states that the purpose of the Act is to ''increase U.S. energy security in cost-effective and environmentally beneficial ways

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[1050] EPA at 51. *See also* NESCAUM at 19; Alliance at 18, 53; Project for Sustainable FERC at 37.

[1051] CCEM argues that the tracking of documentation with environmental compliance requirements will stifle the very competitive bulk power market that EPA and others profess to support. CCEM notes that ''(i)t is both ironic and inexplicable why EPA, the agency charged with enforcing the nation's clean air and other environmental protection laws is so anxious to shift this responsibility away from itself and onto economic participants in the incipient, competitive power supply industry.'' CCEM Supplemental Comments at 4.

[1052] We also note that under EPA's scheme those most likely to benefit from denying access—transmission sellers—would be provided the authority to lawfully deny transmission access.

[1053] EPA states at 51–52 that:

> In implementing section 210 of the Public Utility Regulatory Policies Act, the FERC took the approach of declining to act because of the potential adverse environmental impacts of the action. Section 210 required the FERC to prescribe regulations ''to encourage cogeneration and small power production * * * Because of its concern that ''diesel and dual-fuel commercial cogeneration facilities in the New York City area had the potential to cause environmentally significant effects'' (46 FR 33025) (1981)), the FERC issued regulations that excluded new diesel cogeneration facilities from being ''qualifying facilities.'' 45 FR 17964.

EPA maintains that the FERC similarly has authority in the instant case to deny open access transmission to the extent such transmission would have adverse environmental impacts.

[1054] The Commission subsequently modified this position and decided to treat diesel cogeneration facilities like other QFs.

[1055] *See* CMS Midland, Inc., 50 FERC ¶ 61,098 at 61,277–278 (1990), *reh'g denied*, 56 FERC ¶ 61,177 (1991), *aff'd mem. sub nom.*, Michigan Municipal Cooperative Group, v. FERC, 990 F.2d 1377 (D.C. Cir.) (*per curiam*), *cert. denied*, 114 S.Ct. 546 (1993); *see also* Mesquite Lake Associates, Ltd., 63 FERC ¶ 61,351 (1993); Citizens for Clean Air and Reclaiming Our Environment v. Newbay Corporation, 56 FERC ¶ 61,428 at 62,532–33, *reh'g denied*, 57 FERC ¶ 61,219 (1991).

[1056] Small Power Production and Cogeneration Facilities—Environmental Findings, 10 FERC ¶ 61,314 at 61,632 (1980). The Commission has included similar language in every order it issues finding qualifying facility status. *See also* Small Power Production and Cogeneration, Order No. 70–E, FERC Stats. & Regs., Regs. Preambles 1977–81 ¶ 30,274 at 31,596 (1981).

[1057] The important point is that the Commission has fully complied with its responsibilities under NEPA in both instances. Whatever initial decision it may have come to in 1981 with regard to the particular circumstances involved in adopting QF regulations under PURPA is irrelevant to the instant rulemaking.

[1058] EPA's proposal apparently would apply only for NO_X, CO_2 and mercury. *See* EPA at 58 n.31 and 60 (because there is already a nationwide cap on SO_2 emissions in the Clean Air Act, there is no need for mitigation for that pollutant). In other words, EPA apparently would require us to impose environmental mitigation only in those instances in which Congress has not provided a nationwide cap for a pollutant.

[1059] *See United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*, 350 U.S. 332 (1956); *FPC* v. *Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

[1060] EPA at 59 (emphasis added). *See also* Project for Sustainable FERC at 38–39 (proposing that a regulatory plan be developed through consultations between the Commission, EPA, DOE, and appropriate regional and state regulators and then presented in the FEIS).

* * *.'' [1061] However, even if we assume that the Report language reflects Congressional intent for the Energy Policy Act in general, we note that, in Title VII of the Energy Policy Act concerning electricity, the only mention of the environment was, as noted above, in section 731 which specifically provided that nothing in the Energy Policy Act in any way interferes with the authority of any state or local government relating to, *inter alia*, environmental protection. While we do not quarrel with the proposition that Congress in the Energy Policy Act obviously had concerns with environmental matters,[1062] Congress did not provide the Commission with any authority to mandate environmental mitigation.

We have undertaken an extensive NEPA analysis to consider the environmental effects of our Rule. We cannot, however, take NEPA's requirement to consider environmental effects as authority to require the environmental mitigation proposed in the comments. Congress has charged other agencies, most notably the EPA, with the responsibility of protecting the environment and enforcing environmental laws.[1063] While we stand ready to work in a complementary fashion with these agencies, we believe that any attempt by the Commission to go beyond the economic regulation that Congress has delegated to us would be *ultra vires*.

To summarize: The Commission's jurisdiction under Parts II and III of the FPA is limited to matters relating to economic regulation. Neither the relevant statutes nor the case law supports the expansive and novel reading of the Commission's authority advocated by the commenters that argue that we have environmental mitigation authority. The Commission is not explicitly given such authority in either the FPA or NEPA. Moreover, the FPA and the case law clearly compel the conclusion that we cannot impose environmental conditions that do not directly relate to the economic matters over which we have jurisdiction. To do so, in fact, would prevent the Commission from effectively carrying out its responsibilities under the FPA.

F. Coastal Zone Management Act Issue

By letter dated February 22, 1996, and filed with the Commission on March 5, 1996, the Connecticut Department of Environmental Protection (Connecticut) notified the Commission that it has determined that the Commission's proposed action in this rulemaking proceeding is likely to adversely affect Connecticut's coastal resources. Connecticut reasons that the Rule's promotion of competition ''is likely to increase energy production by mid-west coal burning plants(,) which will in turn increase the export of nitrogen and sulphur oxides.'' Connecticut states that airborne nitrogen emissions are linked to adverse environmental impacts in Long Island Sound. It therefore asserts that, pursuant to section 307(c)(1) of the Coastal Zone Management Act (16 U.S.C. 1456(c)(1)) (CZMA), and the federal regulations promulgated thereunder (15 CFR part 930), the Commission is required to provide it with a determination of the Rules' consistency with Connecticut's federally approved coastal management plan.

Section 307(c)(1)(A) of the CZMA deals with the prevention or amelioration of adverse physical impacts on coastal zone resources attributable to federal activities. The legislative history indicates that in enacting the CZMA Congress was concerned with the adverse effects on coastal lands and waters of such activities as excavation, filling, diversion of water or sediment, clearing, and off-shore energy exploration and dumping.[1064]

As discussed more fully above, section 201 of the FPA declares that the Commission shall *not* have jurisdiction over facilities used for the generation of electricity except as specifically provided. Thus, the Commission has no direct jurisdiction over fossil-fuel plants. Its jurisdiction extends only to the rates, terms, and conditions of wholesale sales and transmission of electric energy in interstate commerce from those plants. While we are aware that the legislative history of the CZMA indicates a Congressional intent to cover all federal activities, there is absolutely no indication in the CZMA or its legislative history that ''federal activities'' should include all federal regulatory decisions, including Commission orders involving interstate electric rates and service (or any other jurisdictional matter under Part II of the FPA).[1065] We are not aware of any judicial or agency interpretation that would cast the net of the states under the CZMA broadly enough to include the generic federal regulatory action undertaken in this Rule. Such action is clearly remote from the kind of activities such as leasing of land, and dredging and filling that either affect, or authorize specific activities that affect, the environment in the coastal zone.

Connecticut's attempt to pull FPA Part II regulation into the CZMA federal consistency provisions by dint of the rulemaking's alleged adverse impact on air quality and consequent adverse impact on water quality in the coastal zone is untenable in view of the existence of the Clean Air Act, a complex, 700-page environmental law that constitutes a comprehensive scheme of regulation of the Nation's air quality, including the direct regulation of emissions by utility power plants. Indeed, the CZMA provides that the requirements of the Clean Air Act, and governmental directives pursuant to that Act, shall be incorporated in, and shall be the air pollution control requirements of, all state coastal zone

[1061] Alliance at 62, *quoting* H.R. Rep. No. 474 (Part I) (Vol. 4), 103d Cong., 2d Sess. 132 (1992), *reprinted in* 1992 U.S. Code Cong. & Ad. News 1955.

[1062] For example, Title XVI concerned Global Climate Change.

[1063] *See, e.g.,* S. Rep. No. 228 (concerning the Clean Air Act Amendments of 1990), 101st Cong., 2d Sess. 5 (1990), *reprinted in* 1990 U.S. Code Cong. & Ad. News 3391 (''The States, together with EPA, are responsible for ensuring that the primary air quality standards are met * * *''); S. Rep. No. 228, 101st Cong., 2d Sess. 9, *reprinted in* 1990 U.S. Code Cong. & Ad. News 3395 (''The 1970 and 1977 Clean Air Act Amendments established a partnership between the States and Federal government. EPA sets nationally uniform air quality standards and States, with the Agency's assistance, are responsible for meeting them.''). *See also, e.g., Connecticut* v. *EPA*, 696 F.2d 147, 163 (2d Cir. 1982) (''One central focus of the Clean Air Act Amendments of 1977 was to ensure that the EPA would monitor and control the impact of pollution from one state on air quality in another.''); *Ohio Environmental Council* v. *EPA*, 593 F.2d 24, 31 (6th Cir. 1979) (''Congress placed responsibility for enforcing the Clean Air Act in the U.S. EPA.'').

We further note the following limitations on the Clean Air Act Amendments of 1990 with respect to the emission allowance program in section 403(f), which provides in pertinent part:

Nothing in this section shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges or affecting any State law regarding such State regulation or as limiting State regulation (including any prudency review) under such a State law. Nothing in this section shall be construed as modifying the Federal Power Act (16 U.S.C.A. 791a et seq.) or as affecting the authority of the Federal Energy Regulatory Commission under that Act. Nothing in this subchapter shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established.

42 U.S.C. 7651b(f). Thus, Congress expressly chose not to tie environmental authority under the emission allowance program to the Commission's and states' ratemaking authority.

[1064] The conference report on the 1990 CZMA amendments expressly states that the principal objective of the 1990 revisions to the language of section 307(c)(1) was to overturn a Supreme Court decision holding that Outer Continental Shelf oil and gas lease sales were not subject to CZMA consistency determinations. H.R. Rep. No. 101–964, 101st Cong., 2d Sess. 2675 (1990).

[1065] In using the phrase ''federal activities'' Congress did not use the term ''federal action'' which has clear and broad meaning under NEPA.

management programs.[1066] It therefore defies logic to assert that, despite the pervasive regulatory reach of the Clean Air Act and the clear authority of EPA to regulate NO_X emissions under that statute, the CZMA is a separate source of authority for state jurisdiction over air quality impacts to coastal zones.

While it is clear that Connecticut's invocation of the CZMA is incorrect, we note that, under the Commerce Department's implementing regulations, Connecticut has in any event waived its right to request a consistency determination for the Commission's rulemaking. Connecticut's coastal management program's list of federal agency activities likely to require a consistency determination does not (for good reason) describe rulemakings of this kind, and the rule will not ''result in a significant change in air or water quality within the management area'' (the program's catch-all category). In addition, Connecticut did not notify the Commission of its conclusion that the Rule requires a consistency determination until well after 45 days from receipt of several notices of the rulemaking proceeding.[1067] Consequently, pursuant to 15 CFR 930.35(b), Connecticut has in any event waived its right to request a consistency determination for this rulemaking.

Conclusion

After reviewing the record in this proceeding, including the FEIS, we find for the reasons discussed above that proceeding with this rule is the best alternative. No other alternative will accomplish the Commission's purposes.

The rule is expected to slightly increase or slightly decrease total future NO_X emissions, depending on whether competitive conditions in the electric industry favor the utilization of natural gas or coal as a fuel for the generation of electricity. Other impacts of the rule have also been determined to be slight. Therefore, it is unnecessary to adopt and implement a plan of mitigation.

A wide range of mitigation measures have nonetheless been fully evaluated as discussed in Chapter 7 of the FEIS. This discussion concludes that the Commission does not have authority under the FPA and NEPA, singly or conjointly, to impose mitigation, and that existing and proposed mitigation strategies and efforts are the best way to deal with potential environmental effects that might result from implementing the rule. Such effects, if they indeed materialize, are not expected to occur for many years. In the meantime, action by entities such as EPA and OTAG are expected to address the underlying air emission problems facing parts of the Nation. Interim mitigation efforts to be undertaken by the Commission would address only a very small part of the problem, would require the exercise of technical expertise and authority that the Commission does not possess, and could well interfere with efforts by EPA and others to address this situation.

For these reasons, we support the analysis in the staff's FEIS and adopt the conclusions in that document.[1068]

VI. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA)[1069] requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities. In the Open Access and Stranded Cost NOPRs, the Commission concluded that the proposed rules would not have a significant economic impact upon a substantial number of small entities.[1070]

SBA questions this conclusion.[1071] It states that, ''[a]ccording to data from the Department of Energy, the vast majority of utilities are small.''[1072] SBA requests that if, upon reconsideration, the Commission determines that the final rule in the Open Access NOPR proceeding would have a significant economic impact on a substantial number of small entities, the Commission perform a Regulatory Flexibility Analysis under the requirements of the RFA.[1073]

A. Docket No. RM95–8–000 (Open Access Final Rule)

1. Public Utilities

The Open Access Final Rule is applicable to public utilities that own, control or operate interstate transmission facilities, not to electric utilities *per se*.[1074] The total number of public utilities that, absent waiver, would have to have open access tariffs on file is 166.[1075] Of these, only 50 public utilities dispose of 4 million MWh or less per year.[1076] Eliminating those utilities that are affiliates of other utilities whose sales exceed 4 million MWh per year, or are not independently owned,[1077] the total number of public utilities affected by the Open Access Final Rule that qualify under the SBA's definition of small electric utility is 19, or 11 percent of the total number of public utilities that would have to have on file open access tariffs.[1078] We do not consider this a substantial number,[1079] and, in any event, these entities may seek waiver of the Open Access Final

[1066] Section 307(f) of the CZMA, 16 U.S.C. 1456(f). A state may develop more stringent standards, if they can be enforced by the state (15 CFR 923.45(c)(2)), but more stringent state air quality standards would not alter the characteristics of FPA Part II regulation that put it beyond the federal consistency requirements of the CZMA.

[1067] The Connecticut Department of Environmental Protection is on the service list for the rulemaking proceeding. The Commission issued a NOPR in this proceeding on March 29, 1995 (60 FR 17662, April 7, 1995). On July 12, 1995, it issued a notice of intent to prepare an EIS in this proceeding (60 FR 36752, July 18, 1995). On November 17, 1995, the Commission issued a Draft EIS (60 FR 58304, Nov. 27, 1995).

[1068] A Record of Decision (ROD) will not be issued as a separate document; instead this rule, including the FEIS as incorporated into the rule by adoption, will serve as the ROD for the rule.

[1069] 5 U.S.C. 601–612.

[1070] 60 FR 17662 at 17721 (April 7, 1995), FERC Stats. & Regs. ¶ 32,514 at 33,151.

[1071] SBA Initial Comments at 1 and n.1.

[1072] SBA Initial Comments at 2 n.1. SBA ''defines a small electric utility as one that disposes of 4 million MWh of electricity in a given year.'' *Id.* At an average wholesale price of between $30 and $40 per MWh (Energy Information Administration, Financial Statistics of Major Investor-Owned Utilities, 1994, Table No. 1), utilities that dispose of 4 million MWh per year would have annual sales in the range of $120 million to $180 million.

[1073] 5 U.S.C. 601–612. SBA Initial Comments at 2 n.1.

[1074] The Stranded Cost Final Rule is applicable to public utilities and to transmitting utilities (that are not also public utilities).

[1075] Over 100 of these entities have already filed some type of open access tariff.

[1076] The sources for this figure are FERC Form No. 1 and FERC Form No. 1–F data.

[1077] The RFA defines a ''small entity'' as ''one which is independently owned and operated and which is not dominant in its field of operation.'' *See* 5 U.S.C. 601(3) and 601(6) and 15 U.S.C. 632(a)(1) (definition of ''small business concern'').

[1078] We note that five of these 19 public utilities have already filed open access tariffs with the Commission. While these five public utilities fall within SBA's definition of small electric utility, since they have already filed open access tariffs, the effect of the Open Access Final Rule on these entities should not be significant. The remaining 14 small public utilities constitute eight percent of the total number of public utilities that would have to have on file open access tariffs. To the extent these 14 small public utilities consider the impact of the Final Rule to be significant, these entities may request a waiver of the open access filing requirements under the waiver provisions of the Open Access Final Rule.

[1079] *In Mid-Tex Electric Coop., Inc.* v. *FERC,* 773 F.2d 327, 340–43 (D.C. Cir. 1985) (*Mid-Tex*), the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term ''small entities'' as defined in the RFA, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP). The CWIP rules applied to *all* public utilities. The Open Access Final Rule applies to *only* those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule.

Rule's requirements under the Rule's waiver provisions.

Moreover, in the Open Access Final Rule, the Commission is specifying the non-rate terms and conditions of the tariffs that the public utilities must have on file. The public utilities need only develop and file a rate.[1080] When one considers that the disposition of 4 million MWhs a year translates into sales in the range of $120 million to $180 million per year, the cost to prepare and file proposed rates,[1081] which these utilities must regularly do anyway in the ordinary course of business, is not a significant economic impact.

2. Non-Public Utilities

The Open Access Final Rule will not impose any burden on non-public utilities, since they need not themselves file open access tariffs. Triggering the reciprocity provision in the Open Access Final Rule is optional; it is merely a condition of receiving a benefit, *i.e.,* open access transmission service from a public utility. If non-public utilities elect not to take advantage of open access services because they do not want to meet the tariff reciprocity provision, they can still seek voluntary, bilateral transmission services from public utilities. Also, under the waiver provisions in the Open Access Final Rule, small non-public utilities may seek waiver from the reciprocity provision.

B. Docket No. RM94–7–001 (Stranded Cost Final Rule)

1. Public Utilities

As with the Open Access Final Rule, there are not a substantial number of public utilities that qualify under the SBA's definition of small electric utility that are subject to the Stranded Cost Final Rule. The Stranded Cost Rule applies only to public utilities that seek stranded cost recovery in connection with a limited set of wholesale requirements contracts (those executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision). To the extent that public utilities seek stranded cost recovery, they will do so in a rate filing, where stranded cost recovery is likely to be one of many items considered. Accordingly, the Stranded Cost Final Rule will not pose a significant economic impact on a substantial number of public utility small entities.

2. Non-Public Utilities

With regard to non-public utilities, the stranded cost issue would only arise in a proceeding under sections 211 and 212 of the FPA when, in directing transmission, the Commission addresses the stranded cost issue in determining a just and reasonable rate. As with public utilities, stranded costs will be just one more item to be considered in establishing just and reasonable rates for transmission. As a result, the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities.

C. Conclusion

Accordingly, the Commission certifies that these final rules will not have a significant economic impact on a substantial number of small entities.

VII. Information Collection Statement

The Office of Management and Budget's (OMB) regulations[1082] require that OMB approve certain information and recordkeeping requirements (collections of information) imposed by an agency. Upon approval of a collection of information, OMB shall assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this Rule shall not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number.

There are now approximately 328 public utilities, including marketers and wholesale generation entities. The Commission estimates that 166 of these utilities own, control or operate facilities used for the transmission of electric energy in interstate commerce and would be subject to the filing requirements of this Rule.

Title: FERC–516, Electric Rate Schedule Filings.

Action: Final Rule.

OMB Control No: 1902–0096.

Respondents: Public Utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce.

Frequency of Responses: On occasion.

Necessity of information: The Final Rule requires public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to have on file with the Commission non-discriminatory open access transmission tariffs that contain minimum terms and conditions of service and permits public utilities to make filings to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and FPA section 211 transmission services. The Commission has a mandate under sections 205 and 206 of the FPA to ensure, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, that no entity is subject to undue discrimination. The Commission will use the data collected in this collection of information to carry out its responsibilities under Part II of the FPA. The Commission's Office of Electric Power Regulation will use the data to review electric rate and tariff filings.

The Commission is submitting notification of this Final Rule to OMB. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC. 20426 [Attention: Michael Miller, Information Services Division, (202) 208–1415], and to the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, (202) 395–3087).

VIII. Effective Date

This Rule will take effect on July 9, 1996. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this rule is a ''major rule'' within the meaning of section 351 of the Small Business Regulatory Enforcement Act of 1996.[1083] The rule will be submitted to both Houses of Congress and the Comptroller General prior to its publication in the Federal Register.

List of Subjects

18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

18 CFR Part 385

Administrative practice and procedure, Electric power, Penalties, Pipelines, Reporting and recordkeeping requirements.

By the Commission. Commissioner Hoecker concurred in part and dissented in

[1080] Those public utilities that already have open access tariffs on file are not even required to propose rates. They may elect to continue service under the Open Access Final Rule's non-rate terms and conditions at their existing rates.

[1081] In the Public Reporting Burden section (Section II), the Commission reaffirms the average reporting burden of 300 hours per response, which was proposed and unchallenged in the NOPR. If a cost of $200 per hour is used, the cost of making the required filing would be $60,000. On average, this is no more than one half of one percent of total annual sales for small electric utilities.

[1082] 5 CFR 1320.11.

[1083] 5 U.S.C. 804(2).

part with a separate statement attached. Commissioner Massey dissented in part with a separate statement attached.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends parts 35 and 385, chapter I, title 18 of the *Code of Federal Regulations,* as set forth below.

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Part 35 is amended by revising § 35.15, by redesignating § 35.28 as § 35.29, and by adding new §§ 35.26, 35.27, and 35.28 to read as follows:

§ 35.15 Notices of cancellation or termination.

(a) *General rule.* When a rate schedule or part thereof required to be on file with the Commission is proposed to be cancelled or is to terminate by its own terms and no new rate schedule or part thereof is to be filed in its place, each party required to file the schedule shall notify the Commission of the proposed cancellation or termination on the form indicated in § 131.53 of this chapter at least sixty days but not more than one hundred-twenty days prior to the date such cancellation or termination is proposed to take effect. A copy of such notice to the Commission shall be duly posted. With such notice each filing party shall submit a statement giving the reasons for the proposed cancellation or termination, and a list of the affected purchasers to whom the notice has been mailed. For good cause shown, the Commission may by order provide that the notice of cancellation or termination shall be effective as of a date prior to the date of filing or prior to the date the filing would become effective in accordance with these rules.

(b) *Applicability.* (1) The provisions of paragraph (a) of this section shall apply to all contracts for unbundled transmission service and all power sale contracts:

(i) Executed prior to July 9, 1996; or

(ii) If unexecuted, filed with the Commission prior to July 9, 1996.

(2) Any power sales contract executed on or after July 9, 1996 that is to terminate by its own terms shall not be subject to the provisions of paragraph (a) of this section.

(c) *Notice.* Any public utility providing jurisdictional services under a power sales contract that is not subject to the provisions of paragraph (a) of this section shall notify the Commission of the date of the termination of such contract within 30 days after such termination takes place.

§ 35.26 Recovery of stranded costs by public utilities and transmitting utilities.

(a) *Purpose.* This section establishes the standards that a public utility or transmitting utility must satisfy in order to recover stranded costs.

(b) *Definitions.*

(1) *Wholesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) A retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

(2) *Wholesale requirements customer* means a customer for whom a public utility or transmitting utility provides by contract any portion of its bundled wholesale power requirements.

(3) *Wholesale transmission services* has the same meaning as provided in section 3(24) of the Federal Power Act (FPA): The transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.

(4) *Wholesale requirements contract* means a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements.

(5) *Retail stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or transmitting utility to provide service to a retail customer that subsequently becomes, in whole or in part, an unbundled retail transmission services customer of that public utility or transmitting utility.

(6) *Retail transmission services* means the transmission of electric energy sold, or to be sold, in interstate commerce directly to a retail customer.

(7) *New wholesale requirements contract* means any *wholesale requirements* contract executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994.

(8) *Existing wholesale requirements* contract means any *wholesale requirements* contract executed on or before July 11, 1994.

(c) *Recovery of wholesale stranded costs.*

(1) *General requirement.* A public utility or transmitting utility will be allowed to seek recovery of wholesale stranded costs only as follows:

(i) No public utility or transmitting utility may seek recovery of wholesale stranded costs if such recovery is explicitly prohibited by a contract or settlement agreement, or by any power sales or transmission rate schedule or tariff.

(ii) No public utility or transmitting utility may seek recovery of stranded costs associated with a new wholesale requirements contract if such contract does not contain an exit fee or other explicit stranded cost provision.

(iii) If wholesale stranded costs are associated with a new wholesale requirements contract containing an exit fee or other explicit stranded cost provision, and the seller under the contract is a public utility, the public utility may seek recovery of such costs, in accordance with the contract, through rates for electric energy under sections 205–206 of the FPA. The public utility may not seek recovery of such costs through any transmission rate for FPA section 205 or 211 transmission services.

(iv) If wholesale stranded costs are associated with a new wholesale requirements contract, and the seller under the contract is a transmitting utility but not also a public utility, the transmitting utility may not seek an order from the Commission allowing recovery of such costs.

(v) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the public utility may seek recovery of stranded costs only as follows:

(A) If either party to the contract seeks a stranded cost amendment pursuant to a section 205 or section 206 filing under the FPA made prior to the expiration of the contract, and the Commission accepts or approves an amendment permitting recovery of stranded costs, the public utility may seek recovery of such costs through FPA section 205–206 rates for electric energy.

(B) If the contract is not amended to permit recovery of stranded costs as described in paragraph (c)(1)(v)(A) of this section, the public utility may file a proposal, prior to the expiration of the contract, to recover stranded costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to the customer.

(vi) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a transmitting

utility but not also a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the transmitting utility may seek recovery of stranded costs through FPA section 211–212 transmission rates.

(vii) If a retail customer becomes a legitimate wholesale transmission customer of a public utility or transmitting utility, *e.g.*, through municipalization, and costs are stranded as a result of the retail-turned-wholesale customer's access to wholesale transmission, the utility may seek recovery of such costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to that customer.

(2) *Evidentiary demonstration for wholesale stranded cost recovery.* A public utility or transmitting utility seeking to recover wholesale stranded costs in accordance with paragraphs (c)(1)(v)–(vii) of this section must demonstrate that:

(i) It incurred stranded costs on behalf of its wholesale requirements customer or retail customer based on a reasonable expectation that the utility would continue to serve the customer;

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a wholesale requirements customer of the utility, or, in the case of a retail-turned-wholesale customer, had the customer remained a retail customer of utility; and

(iii) The stranded costs are derived using the following formula: Stranded Cost Obligation = (Revenue Stream Estimate − Competitive Market Value Estimate)×Length of Obligation (reasonable expectation period).

(3) *Rebuttable presumption.* If a public utility or transmitting utility seeks recovery of wholesale stranded costs associated with an existing wholesale requirements contract, as permitted in paragraph (c)(1) of this section, and the existing wholesale requirements contract contains a notice provision, there will be a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision.

(4) *Procedure for customer to obtain stranded cost estimate.* A customer under an existing wholesale requirements contract with a public utility seller may obtain from the seller an estimate of the customer's stranded cost obligation if it were to leave the public utility's generation supply system by filing with the public utility a request for an estimate at any time prior to the termination date specified in its contract.

(i) The public utility must provide a response within 30 days of receiving the request. The response must include:

(A) An estimate of the customer's stranded cost obligation based on the formula in paragraph (c)(2)(iii) of this section;

(B) Supporting detail indicating how each element in the formula was derived;

(C) A detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract;

(D) An estimate of the amount of released capacity and associated energy that would result from the customer's departure; and

(E) The utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs.

(ii) If the customer disagrees with the utility's response, it must respond to the utility within 30 days explaining why it disagrees. If the parties cannot work out a mutually agreeable resolution, they may exercise their rights to Commission resolution under the FPA.

(5) A customer must be given the option to market or broker a portion or all of the capacity and energy associated with any stranded costs claimed by the public utility.

(i) To exercise the option, the customer must so notify the utility in writing no later than 30 days after the public utility files its estimate of stranded costs for the customer with the Commission.

(A) Before marketing or brokering can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount and the price of capacity and associated energy the customer is entitled to schedule, and the duration of the customer's marketing or brokering of such capacity and energy.

(ii) If agreement over marketing or brokering cannot be reached, and the parties seek Commission resolution of disputed issues, upon issuance of a Commission order resolving the disputed issues, the customer may reevaluate its decision in paragraph (c)(5)(i) of this section to exercise the marketing or brokering option. The customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

(iii) If a customer undertakes the brokering option, and the customer's brokering efforts fail to produce a buyer within 60 days of the date of the brokering agreement entered into between the customer and the utility, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula in paragraph (c)(2)(iii) of this section.

(d) *Recovery of retail stranded costs.*

(1) *General requirement.* A public utility may seek to recover retail stranded costs through rates for retail transmission services only if the state regulatory authority does not have authority under state law to address stranded costs at the time the retail wheeling is required.

(2) *Evidentiary demonstration necessary for retail stranded cost recovery.* A public utility seeking to recover retail stranded costs in accordance with paragraph (d)(1) of this section must demonstrate that:

(i) It incurred stranded costs on behalf of a retail customer that obtains retail wheeling based on a reasonable expectation that the utility would continue to serve the customer; and

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a retail customer of the utility.

§ 35.27 Power sales at market-based rates.

(a) Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.

(b) Nothing in this part

(1) Shall be construed as preempting or affecting any jurisdiction a state commission or other state authority may have under applicable state and federal law, or

(2) Limits the authority of a state commission in accordance with state and federal law to establish

(i) Competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or

(ii) Non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with state law.

§ 35.28 Non-discriminatory open access transmission tariff.

(a) *Applicability.* This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in

interstate commerce and to any non-public utility that seeks voluntary compliance with jurisdictional transmission tariff reciprocity conditions.

(b) *Definitions.*

(1) *Requirements service agreement* means a contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.

(2) *Economy energy coordination agreement* means a contract, or service schedule thereunder, that provides for trading of electric energy on an ''if, as and when available'' basis, but does not require either the seller or the buyer to engage in a particular transaction.

(3) *Non-economy energy coordination agreement* means any non-requirements service agreement, except an economy energy coordination agreement as defined in paragraph (b)(2) of this section.

(c) *Non-discriminatory open access transmission tariffs.*

(1) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs) or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), and (c)(1)(iv) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls or operates facilities used for the transmission of electric energy in interstate commerce as of July 9, 1996, it must file the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA, no later than July 9, 1996. However, if a public utility has already filed, or has on file, an open access tariff and accompanying rates as of April 24, 1996, it may, but is not required to, file new rates with its section 206 pro forma tariff filing.

(iii) If a public utility owns, controls or operates transmission facilities used for the transmission of electric energy in interstate commerce as of July 9, 1996, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file no later than December 31, 1996 the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

(iv) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the pro forma tariff required by this section.

(v) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs. ¶ 31,036.

(2) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the open access tariff filed pursuant to this section.

(i) Subject to the exceptions in paragraphs (c)(2)(ii) and (c)(3)(iv) of this section, this requirement is effective on the date that such public utility engages in a wholesale sale or purchase of electric energy or any unbundled retail sale of electric energy, but no earlier than July 9, 1996.

(ii) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(3) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must file a joint pool-wide or system-wide open access transmission pro forma tariff.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after July 9, 1996, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any public utility holding company arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996, this requirement is effective July 9, 1996, except for the Central and South West System, which must comply no later than December 31, 1996.

(iii) For any power pool or multi-lateral arrangement or agreement other than a public utility holding company arrangement or agreement, that contains transmission rates, terms or conditions and that is executed prior to July 9, 1996, this requirement is effective on December 31, 1996.

(iv) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must begin to take service under a joint pool-wide or system-wide pro forma tariff for wholesale trades among the pool or system members no later than December 31, 1996.

(d) *Waivers.* A public utility subject to the requirements of this section and Order No. 889, FERC Stats. & Regs. ¶ 31,037 (Final Rule on Open Access Same-Time Information System and Standards of Conduct) may file a request for waiver of all or part of the requirements of this section, or Part 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities), for good cause shown. An application for waiver must be filed either:

(i) No later than July 9, 1996 or

(ii) No later than 60 days prior to the time the public utility would otherwise have to comply with the requirement.

(e) *Non-public utility procedures for tariff reciprocity compliance.*

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888 (Final Rule on Open Access and Stranded Costs).

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 case against the non-public utility shall have the burden of proof to show why service under the open access tariff is not sufficient and why a section 211 order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access tariff, for good cause shown. An application for waiver may be filed at any time.

PART 385—RULES OF PRACTICE AND PROCEDURE

1. The authority citation for part 385 continues to read as follows:

Authority: 5 U.S.C. 551–557; 15 U.S.C. 717–717z, 3301–3432; 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352; 49 U.S.C. 60502; 49 App. U.S.C. 1–85.

2. Part 385 is amended by adding paragraph (b)(5) to § 385.2011 to read as follows:

§ 385.2011 Procedures for filing on electronic media (Rule 2011).

* * * * *

(b) * * *

(5) Non-discriminatory open access transmission tariffs filed pursuant to § 35.28 of this chapter.

* * * * *

Note: Appendices A through H and statements of Commissioners Hoecker and Massey will not be published in the Code of Federal Regulations.

LIST OF SECTION 211 APPLICATIONS

No.	Docket No.	Applicant	Transmitter	Commission action
1	TX93–1–000	Tex-La Electric Cooperative of Texas, Inc.	Texas Utilities Electric Company	Denied, 64 FERC ¶ 61,162.
2	TX93–2–000	City of Bedford, Virginia, et al	American Electric Power Company, Inc.	Granted. Final order, 68 FERC ¶ 61,003. Reh'g denied, 73 FERC ¶ 61,322.
3	TX93–3–000	Wisconsin Electric Power Company	Upper Peninsula Power Company	Withdrawn 9/10/93.
4	TX93–4–000	Florida Municipal Power Agency	Florida Power & Light Company	Granted. Final order, 67 FERC ¶ 61,167. Order on reh'g, 74 FERC ¶ 61,006.
5	TX94–1–000	Minnesota Municipal Power Agency	Northern States Power Company	Granted. Proposed order, 66 FERC ¶ 61,114. Reh'g denied, 66 FERC ¶ 61,323 Settlement accepted by letter order, 68 FERC ¶ 61,031.
6	TX94–2–000	El Paso Electric Company, et al	Southwestern Public Service Company	Proposed order, 68 FERC ¶ 61,182; order on reh'g, 68 FERC ¶ 61,399; order dismiss'g proceeding, 72 FERC ¶ 61,292.
7	TX94–3–000	Minnesota Municipal Power Agency	Southern Minnesota Municipal Power Agency.	Granted. Proposed order, 66 FERC ¶ 61,223; reh'g denied, 67 FERC ¶ 61,075; Final order, 68 FERC ¶ 61,060.
8	TX94–4–000	Tex-La Electric Cooperative of Texas, Inc.	Texas Utilities Electric Company	Granted. Proposed order, 67 FERC ¶ 61,019; Final order, 69 FERC ¶ 61,269.
9	TX94–5–000	Old Dominion Electric Cooperative, Inc	Delmarva Power & Light Company	Granted. Proposed order, 68 FERC ¶ 61,169. Settl'd, 69 FERC ¶ 61,436, 70 FERC ¶ 61,082.
10	TX94–6–000	Reading Municipal Light Department	16 New England Transmitting Utilities	Terminated July 10, 1995 by OEPR Letter Order, following notice of withdrawal filed May 8, 1995.
11	TX94–7–000	AES Power, Inc	Tennessee Valley Authority	Granted. Final Order issued Feb. 29, 1996, 74 FERC ¶ 61,220, reh'g pending.
12	TX94–8–000	Duquesne Light Company	PJM Companies	Granted. Proposed order issued 5/16/95, 71 FERC ¶ 61,155.
13	TX94–9–000	Borough of Zelienople, Pennsylvania	Pennsylvania Power Company	Granted. Proposed order issued 1/25/95, 70 FERC ¶ 61,073.
14	TX94–10–000	Duquesne Light Company	Allegheny Power System	Granted. Proposed order issued 5/16/95, 71 FERC ¶ 61,156.
15	TX95–1–000	Enron Power Marketing, Inc	Consolidated Edison Co. of New York	Pending. Comments due 11/3/94.
16	TX95–2–000	Wisconsin Public Power Inc. SYSTEM	WEPCO, WP&L, WPSC	Pending. Comments due 11/16/94.
17	TX95–3–000	Municipal Energy Agency of Nebraska	Nebraska Public Power District and Tri-State Generation and Transmission Association, Inc.	w/drawn 11–16–95
18	TX95–4–000	American Municipal Power-Ohio, Inc	Ohio Edison Company	Granted. Proposed Order issued Feb. 1, 1996 74 FERC ¶ 61,086.
19	TX95–5–000	United States Department of Energy—Southeastern Power Administration.	Southern Company System	Pending.
20	TX95–6–000	Cleveland Public Power	Centerior Energy Corporation	Rejected Without Prejudice 72 FERC ¶ 61,189.
21	TX95–7–000	Cleveland Public Power	Cleveland Electric Illuminating Company and Toledo Edison Company.	Pending.
22	TX96–1–000	Citizens Utilities Company	Swanton Village, Vermont	Pending.

LIST OF SECTION 211 APPLICATIONS—Continued

No.	Docket No.	Applicant	Transmitter	Commission action
23	TX96–2–000	City of College Station, Texas	City of Bryan, Texas and Texas Municipal Power Agency.	Pending.
24	TX96–3–000	Citizens Utilities Company	Swanton Village, Vermont	Pending.
25	TX96–4–000	Suffolk County Electrical Agency	Long Island Lighting Company	Pending.
26	TX96–5–000	United States Department of Energy—Western Area Power Administration.	Public Service Company of New Mexico.	Pending.
27	TX96–6–000	Montana Power Company	Basin Electric Cooperative	Pending.
28	TX96–7–000	City of Palm Springs, California	Southern California Edison Company	Pending.

Appendix B—List of Commenters

Abbreviation	Commenter
1. ABATE	Association of Businesses Advocating Tariff Equity.
2. AEC & SMEPA	Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association.
3. AEP	American Electric Power System.
4. AGA	American Gas Association.
5. Air Liquide	Air Liquide America Corporation.
6. AL Com	Alabama Public Service Commission.
7. ALCOA	Aluminum Company of America.
8. Allegheny	Allegheny Power Service Corporation.
9. Alma	City of Alma, Michigan.
10. Aluminum	Aluminum Association.
11. American Forest & Paper	American Forest & Paper Association.
12. American Iron & Steel	American Iron & Steel Institute American Forest & Paper Association, American Public Power Association, Chemical Manufacturers Association, Citizen Action, Council of Industrial Boiler Owners, Electricity Consumers Resource Council, Environmental Action Foundation, City of Las Cruces, New Mexico, City of Westbrook, Maine, Sovereign California Cities Joint Powers Committee, Toward Utility Rate Normalization.
13. American National Power	American National Power, Inc.
14. American Wind	American Wind Energy Association.
15. AMP-Ohio	American Municipal Power-Ohio, Inc. and Indiana Municipal Power Agency.
16. Anaheim	Cities of Anaheim, Azusa, Banning, Colton and Riverside, California.
17. Anchorage	Anchorage Municipal Light and Power.
18. Anoka EC	Anoka Electric Cooperative.
19. APPA	American Public Power Association.
20. APS Customers	APS Wholesale Customer Group (Aquila Irrigation District, Buckeye Water Conservation District, Electrical District No. 3 of Pinal County, Electrical District No. 6 of Pinal County, Electrical District No. 7 of Maricopa County, Electrical District No. 8 of Maricopa County, Harquahala Valley Power District, Maricopa County Municipal Water Conservation District No. 1, McMullan Valley Water Conservation District, Roosevelt Irrigation District and Tonopah Irrigation District).
21. Arcadia	Arcadia Resources, Inc.
22. Arizona	Arizona Public Service Company.
23. Arizona EC	Arizona Electric Power Cooperative.
24. Ark Elec	Arkansas Electric Cooperative Corporation.
25. Arkansas Cities	Arkansas Cities and Farmers Electric Cooperative.
26. Associated EC	Associated Electric Cooperative, Inc.
27. Associated Power	Associated Power Services, Inc.
28. Atlantic City	Atlantic City Electric Company.
29. AZ Com	Arizona Corporation Commission.
30. Baker EC	Baker Electric Cooperative, Inc.
31. Baltimore Transp Bureau	Transportation Bureau of Baltimore, Inc.
32. Basin EC	Basin Electric Power Cooperative.
33. BG&E	Baltimore Gas and Electric Company.
34. Big Horn REC	Big Horn Rural Electric Company.
35. Big Rivers EC	Big Rivers Electric Cooperative.
36. Black Hills EC	Black Hills Electric Cooperative.
37. Black Mayors	National Conference of Black Mayors.
38. Blue Ridge	Blue Ridge Power Agency, Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc.
39. Bon Homme Yankton EC	Bon Homme Yankton Electric Association, Inc.
40. Boston Edison	Boston Edison Company.
41. Boulder	City of Boulder, Colorado.
42. BPA	Bonneville Power Administration.
43. Brazos	Brazos Electric Power Cooperative, Inc.
44. Brownsville	Brownsville, Texas Public Utilities Board.
45. Building Owners	Building Owners and Managers Association International.
46. CA Cogen	Cogeneration Association of California.
47. CA Com	California Public Utilities Commission.

Abbreviation	Commenter
48. CA Energy Co	California Energy Company, Inc.
49. CA Energy Com	California Energy Commission.
50. Cajun	Cajun Electric Power Cooperative, Inc.
51. California DWR	California Department of Water Resources.
52. California Water Agencies	Association of California Water Agencies.
53. Calpine	Calpine Corporation.
54. CAMU	Colorado Association of Municipal Utilities.
55. Canada	Canadian Embassy.
56. Canadian Petroleum Producers	Canadian Association of Petroleum Producers.
57. Caparo	Caparo Steel.
58. Carbon Power	Carbon Power & Light Inc.
59. Carolina P&L	Carolina Power & Light Company.
60. CCEM	Coalition for a Competitive Electric Market (consisting of Catex Vitol Electric, Inc., Coastal Electric Services Company, Destec Power Services, Inc., Electric Clearinghouse, Inc., Enron Power Marketing, Inc., Equitable Power Services Company, KCS Power Marketing, Inc. and MidCon Power Services Corp.).
61. Centerior	Centerior Energy Corporation.
62. Central EC	Central Electric Power Cooperative.
63. Central Hudson	Central Hudson Gas & Electric Corporation.
64. Central Illinois Light	Central Illinois Light Company.
65. Central Illinois Public Service	Central Illinois Public Service Company.
66. Central Louisiana	Central Louisiana Electric Company, Inc.
67. Central Montana EC	Central Montana Electric Power Cooperative, Inc.
68. Christensen	Laurits R. Christensen Associates Inc.
69. Chugach	Chugach Electric Association, Inc.
70. CINergy	CINergy Corp.
71. Citizens Lehman	Citizens Lehman Power L.P.
72. Citizens Utilities	Citizens Utilities Company.
73. Clark	Clark Public Utilities.
74. Clean Air	Clean Air Action Corporation.
75. Cleveland	Cleveland Public Power.
76. CO Com	Colorado Public Utilities Commission Staff.
77. CO Consumers Counsel	Colorado Office of Consumer Counsel.
78. Coalition for Economic Competition	Coalition for Economic Competition (consisting of Central Hudson Gas & Electric Corporation, Central Maine Power Company, Consolidated Edison Company of New York, Inc., Illinois Power Company, Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.
79. Coalition on Federal-State Issues	Coalition on Federal-State Issues of the Power Marketing Association.
80. Com Ed	Commonwealth Edison Company.
81. Com Electric	Commonwealth Electric Company.
82. Competitive Enterprise	Competitive Enterprise Institute.
83. Concord	Concord Municipal Light Plant.
84. ConEd	Consolidated Edison Company of New York, Inc.
85. Conservation Law Foundation	Conservation Law Foundation and Center for Efficiency and Renewable Technologies.
86. Consolidated Natural Gas	Consolidated Natural Gas Company.
87. Consumers Power	Consumers Power Company.
88. Continental Power Exchange	Continental Power Exchange, Inc.
89. Cooperative Power	Cooperative Power.
90. CSW	Central and South West Corporation.
91. CT DPUC	Connecticut Department of Public Utility Control.
92. CT Munis	Connecticut Conference of Municipalities.
93. CVPSC	Central Vermont Public Service Corporation.
94. Dairyland	Dairyland Power Cooperative.
95. Dayton P&L	Dayton Power and Light Company.
96. DC Com	Public Service Commission of the District of Columbia.
97. DE Muni	Delaware Municipal Electric Corporation, Inc.
98. DE, DC, NJ and MD Coms	Delaware Public Service Commission, District of Columbia Public Service Commission, Maryland Public Service Commission, and New Jersey Board of Public Utilities.
99. Deloitte & Touche	Deloitte & Touche LLP.
100. Destec	Destec Energy.
101. Detroit Edison	Detroit Edison Company.
102. Detroit Edison	Detroit Edison Wholesale Customers (consisting of City of Croswell, Michigan, and Thumb Electric Cooperative).
103. Direct Service Industries	Direct Service Industries (consisting of ELF Atochem North America, Inc., Columbia Columbia Aluminum Corporation, Columbia Falls Aluminum Co., Georgia Pacific, Kaiser Aluminum & Chemical Corporation, Intalco Aluminum, Northwest Aluminum Company, Reynolds Metals Company and Vanalco, Inc.).
104. DOD	Department of Defense.
105. DOE	United States Department of Energy.
106. DOJ	United States Department of Justice.
107. Dominion	Dominion Resources.
108. Douglas EC	Douglas Electric Cooperative, Inc.
109. Duke	Duke Power Company.

Abbreviation	Commenter
110. Duquesne	Duquesne Light Company.
111. East Kentucky	East Kentucky Power Cooperative, Big Rivers Electric Corporation, and Hoosier Energy Rural Electric Cooperative.
112. East River EC	East River Electric Power Cooperative.
113. EDS Utilities	Electronic Data Systems Inc., Utilities Division (Joussef Heguzy, Clifford J. Meagh, Julius A. Wright).
114. Education	American Council on Education and the National Association of College and University Business Officers
115.	EEI Edison Electric Institute.
116. EGA	Electric Generation Association.
117. El Paso	El Paso Electric Company.
118. ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute, Chemical Manufacturers Association and Council of Industrial Boiler Owners.
119. Electric Consumers Alliance	Electric Consumers' Alliance.
120. Electronic Data Systems	EDS Utilities Division (James F. Susman).
121. ENEREX	ENEREX, Inc.
122. Entergy	Entergy Services, Inc.
123. Entergy Retail Regulators	Arkansas Public Service Commission, City Council of New Orleans, Louisiana Public Service Commission, and Mississippi Public Service Commission.
124. Environmental Action	Environmental Action Foundation.
125. EPA	United States Environmental Protection Agency.
126. Fertilizer Institute	The Fertilizer Institute.
127. FL Com	Florida Public Service Commission.
128. Florida Power Corp	Florida Power Corporation.
129. FPL	Florida Power & Light Company.
130. Freedom Energy Co	Freedom Energy Company, LLC.
131. FTC	United States Federal Trade Commission, Staff of the Bureau of Economics.
132. Fuel Managers	Fuel Managers Association.
133. GA Com	Georgia Public Service Commission.
134. GAPP Committee	General Agreement of Parallel Paths Committee (A. Garfield).
135. Graves	Graves, Frank and Ilic, Marija.
136. Green Mountain	Green Mountain Power Corporation.
137. Heartland	Heartland Consumers Power District.
138. Hogan	Hogan, William W.
139. Home Builders	National Association of Home Builders.
140. Homelessness Alliance	National Alliance to End Homelessness, Inc.
141. Hoosier EC	Hoosier Energy Rural Electric Cooperative.
142. Hopkinsville EC	Hopkinsville Electric System.
143. Houston L&P	Houston Lighting & Power Company.
144. Hydro-Quebec	Hydro-Quebec.
145. IA Com	Iowa Utilities Board.
146. IBM	International Business Machines.
147. ID Com	Idaho Public Utilities Commission.
148. Ida County REC	Ida County Rural Electric Cooperative.
149. Idaho	Idaho Power Company.
150. IES Utilities	IES Utilities Inc.
151. IL Com	Illinois Commerce Commission.
152. IL Industrials	Illinois Industrial Energy Consumers.
153. Illinois Municipal Electric Agency	Illinois Municipal Electric Agency.
154. Illinois Power	Illinois Power Company.
155. IN Com	Indiana Utility Regulatory Commission.
156. IN Industrials	Indiana Industrial Energy Consumers, Inc.
157. Industrial Energy Applications	Industrial Energy Applications.
158. Inland Power Pool	Inland Power Pool.
159. IPALCO	IPALCO Enterprises, Inc.
160. James Valley EC	James Valley Electric Cooperative, Inc.
161. Jay	Town of Jay, Maine and the Jay Power District.
162. KCPL	Kansas City Power & Light Company.
163. Knoxville	Knoxville Utilities Board.
164. KS Com	Kansas Corporation Commission Staff.
165. KU	Kentucky Utilities Company.
166. KY AG	Kentucky Attorney General.
167. KY Com	Kentucky Public Service Commission.
168. LA DWP	Department of Water and Power of the City of Los Angeles.
169. LA Industrials	Louisiana Energy Users Group.
170. La Raza	National Council of La Raza.
171. Las Cruces	City of Las Cruces, New Mexico.
172. Latin League	League of United Latin American Citizens.
173. Legal Environmental Assistance	Legal Environmental Assistance Foundation.
174. LEPA	Louisiana Energy and Power Authority.
175. Lester Fink	Fink, Lester.
176. LG&E	LG&E Energy Corp.
177. LILCO	Long Island Lighting Company.
178. Lincoln-Union EC	Lincoln-Union Electric Company.

Abbreviation	Commenter
179. Lively	Lively, Mark B.
180. Local Furnishing Utilities	Local Furnishing Utilities (Long Island Lighting Company, Nevada Power Company, and San Diego Gas & Electric Company).
181. Lower Colorado River Authority	Lower Colorado River Authority.
182. LPPC	Large Public Power Council.
183. MA DPU	Massachusetts Department of Public Utilities.
184. Madison G&E	Madison Gas & Electric Company.
185. Maine Public Service	Maine Public Service Company.
186. Maritime	Maritime Electric Company.
187. McKenzie EC	McKenzie Electric Cooperative, Inc.
188. MD Com	Maryland Public Service Commission.
189. ME Consumer-Owned Utilities	Maine Consumer-Owned Utilities (consisting of Eastern Maine Electric Cooperative, Inc., Fox Islands Electric Cooperative, Inc. Houlton Water Company, Isle au Haut Electric Power Co., Kennebunk Light & Power District, Madison Electric Works, Swans Island Electric Cooperative, Inc., and Van Buren Light & Power District).
190. ME Industrials	Industrial Energy Consumer Group of Maine.
191. MEAG	Municipal Electric Authority of Georgia.
192. Memphis	Memphis Light, Gas and Water Division.
193. Mercer	Mercer, Dorothy Ph.D.
194. MI Com	Michigan Public Service Commission.
195. MI MEA	Municipal Energy Agency of Mississippi.
196. Michigan Coalition	Consumers Power, Detroit Edison and Michigan Public Service Commission.
197. Michigan Systems	Florida Municipal Power Agency, Michigan Public Power Agency, Michigan South Central Power Agency, Michigan Public Power Ratepayers Association and Wolverine Power Supply Cooperative.
198. MidAmerican	MidAmerican Energy Company.
199. Midwest Commissions	Arkansas, Kansas & Missouri State Commissions.
200. Minnesota P&L	Minnesota Power & Light Company.
201. Missouri Basin Group	Missouri Basin Systems Group, Inc.
202. Missouri Basin MPA	Missouri Basin Municipal Power Agency.
203. Missouri Joint Commission	Missouri Joint Municipal Electric Utilities Commission.
204. Missouri-Kansas Industrials	Missouri-Kansas Industrial Energy Consumers.
205. MMWEC	Massachusetts Municipal Wholesale Electric Company.
206. MN DPS	Minnesota Department of Public Service.
207. Montana Power	Montana Power Company.
208. Montana-Dakota Utilities	Montana-Dakota Utilities Company.
209. Montaup	Montaup Electric Company.
210. Mor-Gran-Sou EC	Mor-Gran-Sou Electric Cooperative.
211. Mountain States Petroleum Assoc	Independent Petroleum Association of Mountain States and Colorado Oil and Gas Association.
212. MS Com	Mississippi Public Service Commission.
213. MT Com	Montana Public Service Commission.
214. MT Dept of Environmental Quality	Montana Department of Environmental Quality.
215. Mt. Hope Hydro	Mt. Hope Hydro, Inc.
216. Municipal Energy Agency Nebraska	Municipal Energy Agency of Nebraska.
217. NARUC	National Association of Regulatory Utility Commissioners.
218. NASUCA	National Association of State Utility Consumer Advocates.
219. National Hydropower	National Hydropower Association.
220. National Women's Caucus	National Women's Political Caucus.
221. Natural Resources Defense	Natural Resources Defense Council and Pacific Gas and Electric Company.
222. NC Com	North Carolina Utilities Commission.
223. NCMPA	North Carolina Municipal Power Agency Number 1.
224. NCPA	Northern California Power Agency.
225. ND Com	North Dakota Public Service Commission.
226. NE Public Power District	Nebraska Public Power District.
227. NE States Air Management	Northeast States for Coordinated Air Use Management.
228. NEPCO	New England Power Company.
229. NEPOOL	New England Power Pool Executive Committee.
230. NEPOOL Review Committee	New England Public Power NEPOOL Review Committee.
231. NERC	North American Electric Reliability Council.
232. Nevada	Nevada Power Company.
233. New Brunswick	New Brunswick Power.
234. NGSA	Natural Gas Supply Association.
235. NH Com	New Hampshire Public Utilities Commission.
236. NH General Court	Retail Wheeling & Restructuring Committee of the New Hampshire General Court.
237. NIEP	National Independent Energy Producers.
238. NIMO	Niagara Mohawk Power Corporation.
239. NIPSCO	Northern Indiana Public Service Company.
240. NJ BPU	New Jersey Board of Public Utilities.
241. NJ Ratepayer Advocate	New Jersey Division of the Ratepayer Advocate.
242. NM Com	New Mexico Public Utility Commission.
243. NM Industrials	New Mexico Industrial Energy Consumers.
244. NorAm	NorAm Energy Services, Inc.
245. Nordhaus	Nordhaus, William D.
246. North Dakota RECs	North Dakota Association of Rural Electric Cooperatives.

Abbreviation	Commenter
247. NRECA	National Rural Electric Cooperative Association.
248. NRECA/APPA	National Rural Electric Cooperative Association and APPA.
249. NRRI	National Regulatory Research Institute.
250. NSP	Northern States Power Company.
251. NU	Northeast Utilities System Companies.
252. Nuclear Energy Institute	Nuclear Energy Institute.
253. Nucor	Nucor Corporation.
254. NV Com	Public Service Commission of Nevada.
255. NW Conservation Act Coalition	Northwest Conservation Act Coalition.
256. NW Iowa Cooperative	Northwest Iowa Power Cooperative.
257. NW Power Planning Council	Northwest Power Planning Council.
258. NWRTA	Northwest Regional Transmission Association.
259. NY AG	New York State Attorney General.
260. NY Com	Public Service Commission of the State of New York.
261. NY Consumer Protection	New York Consumer Protection Board.
262. NY Energy Buyers	New York Energy Buyers Forum.
263. NY Industrials	Multiple Industrial Intervenors of New York.
264. NY IOUs	Long Island Lighting, New York State Electric & Gas and Rochester Gas & Elec.
265. NY Mayors	New York State Conference of Mayors and Municipal Officals.
266. NYMEX	New York Mercantile Exchange.
267. NYPP	New York Power Pool.
268. NYSEG	New York State Electric & Gas Corporation.
269. Oahe EC	Oahe Electric Cooperative, Inc.
270. Oak Ridge	Oak Ridge National Laboratory.
271. Occidental Chemical	Occidental Chemical Corporation.
272. Oglethorpe	Oglethorpe Power Corporation.
273. OH Com	Public Utilities Commission of Ohio.
274. OH Coops	Ohio Rural Electric Cooperatives, Inc. and Buckeye Power, Inc.
275. OH Industrials	Industrial Energy Users—Ohio.
276. Ohio Edison	Ohio Edison Company.
277. Ohio Manufacturers	Ohio Manufacturers' Association.
278. Ohio Valley	Ohio Valley Electric Corporation.
279. OK Com	Oklahoma Corporation Commission.
280. Oklahoma G&E	Oklahoma Gas and Electric Company.
281. Old Dominion EC	Old Dominion Electric Cooperative, Inc.
282. Oliver-Mercer EC	Oliver-Mercer Electric Cooperative, Inc.
283. Omaha PPD	Omaha Public Power District.
284. Ontario Hydro	Ontario Hydro.
285. Orange & Rockland	Orange and Rockland Utilities, Inc.
286. Oregon Trail EC	Oregon Trail Electric Cooperative, Inc.
287. Otter Tail	Otter Tail Power Company.
288. PA Com	Pennsylvania Public Utility Commission.
289. PA Coops	Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc.
290. PA Industrials	Industrial Energy Consumers of Pennsylvania.
291. PA Munis	Pennsylvania Municipal Electric Association.
292. Pacific Northwest Coop	Pacific Northwest Generating Cooperative.
293. PacifiCorp	PacifiCorp.
294. Panhandle Coop	Panhandle Rural Electric Membership Association.
295. PECO	PECO Energy Company.
296. Pennsylvania P&L	Pennsylvania Power & Light Company.
297. PG&E	Pacific Gas and Electric Company.
298. Phelps Dodge	Phelps Dodge Corporation.
299. Philip Morris	Philip Morris Management Corp.
300. PJM	PJM—Pennsylvania New Jersey Maryland Interconnection.
301. Portland	Portland General Electric Company.
302. Power Marketing Association	Power Marketing Association.
303. PSE&G	Public Service Electric and Gas Company.
304. PSNM	Public Service Company of New Mexico.
305. Public Generating Pool	Public Generating Pool.
306. Public Power Council	Public Power Council.
307. Public Service Co of CO	Public Service Company of Colorado and Cheyenne Light, Fuel and Power Company.
308. Puget	Puget Sound Power & Light Company.
309. Redding	Cities of Redding and Santa Clara, California.
310. Reynolds	Reynolds Metals Company.
311. Rochester G&E	Rochester Gas and Electric Corporation.
312. Rocky Mountain Institute	Rocky Mountain Institute (Amory Lovins).
313. Rosebud	Rosebud Enterprises, Inc.
314. RUS	Rural Utilities Service (formerly REA).
315. Rushmore EC	Rushmore Electric Power Cooperative, Inc.
316. Salt River	Salt River Project Agriculture Improvement and Power District.
317. San Diego G&E	San Diego Gas & Electric Company.
318. San Francisco	City and County of San Francisco.
319. San Luis Valley REC	San Luis Valley Rural Electric Cooperative.
320. SBA	United States Small Business Administration, Office of Advocacy.

Abbreviation	Commenter
321. SC Com	South Carolina Public Service Commission.
322. SCE&G	South Carolina Electric & Gas Company.
323. SC Public Service Authority	South Carolina Public Service Authority.
324. Seattle	Seattle City Light Department.
325. Seminole EC	Seminole Electric Cooperative, Inc.
326. SEPA	Southeastern Power Administration/Federal Power Customers.
327. Shelby County	Shelby County Board of Commissioners.
328. Sierra	Sierra Pacific Power Company.
329. Slope EC	Slope Electric Cooperative Inc.
330. SMUD	Sacramento Municipal Utility District.
331. Snohomish	Public Utility District No. 1 of Snohomish County, Washington.
332. SoCal Edison	Southern California Edison Company.
333. SoCal Gas	Southern California Gas Company.
334. South Jersey Gas	South Jersey Gas Company.
335. Southern	Southern Company Services, Inc.
336. Southwest TDU Group	Southwest Transmission Dependent Utility Group (consisting of Aguila Irrigation District, Ak-Chin Indian Community, Buckeye Irrigation District, Central Arizona Water Conservation District, Electrical District No. 3, No. 4, No. 5, No. 6, No. 7, Harquahala Valley Power District, Maricopa Water District, McMullen Valley Water Conservation and Drainage District, City of Needles, Roosevelt Irrigation District, City of Safford, Tonopah Irrigation District, Wellton-Mohawk Irrigation and Drainage District).
337. Southwestern	Southwestern Public Service Company.
338. Soyland	Soyland Power Cooperative.
339. Spink EC	Spink Electric, Redfield, SD.
340. SPP	Southwest Power Pool, Inc.
341. Springfield	City Utilities of Springfield, Missouri.
342. St. Joseph	St. Joseph Light & Power Company.
343. Suffolk County	Suffolk County (New York) Electric Agency.
344. Sunflower	Sunflower Electric Power Corporation.
345. Supervised Housing	State and City Supervised Housing for Equity in Electric Rates.
346. Sustainable Energy Policy	Project For Sustainable FERC Energy Policy (on behalf of Alliance for Affordable Energy, Citizens Action Coalition of Indiana, Conservation Law Foundation, Environmental Defense Fund, Environmental Law & Policy Center of the Midwest, Izaak Walton League of America, Land and Water Fund of the Rockies, Legal Environmental Assistance Foundation, Mid-Atlantic Energy Project, Minnesotans for an Energy-Efficient Economy, Natural Resources Defense Council, Northwest Conservation Act Coalition, Pace Energy Project, Public Citizen, Texas, RENEW Wisconsin, Southern Environmental Law Center, Texas Ratepayers' Organization to Save Energy, Union of Concerned Scientists, and Wisconsin's Environmental Decade).
347. Tallahassee	City of Tallahassee, Florida.
348. Tampa	Tampa Electric Company.
349. TANC	Transmission Agency of Northern California.
350. TAPS	Transmission Access Policy Study Group.
351. TDU Systems	Transmission Dependent Utility Systems (Arkansas Electric Cooperative Corporation, Connecticut Municipal Electric Energy Cooperative, Golden Spread Electric Cooperative, Inc., Holy Cross Electric Association, Inc., Kansas Electric Power Cooperative, Inc., Magic Valley Electric Cooperative, Inc., Mid-Tex Generation & Transmission Electric Cooperative, Inc., NewCorp Resources, Inc., Old Dominion Electric Cooperative, Inc.).
352. Texaco	Texaco Inc.
353. Texas Utilities	Texas Utilities Electric Company.
354. Texas-New Mexico	Texas-New Mexico Power Company.
355. Tonko	Tonko, Paul D. (NY State Assembly).
356. Torco	Torco Energy Marketing, Inc.
357. Total Petroleum	Total Petroleum, Inc.
358. Traverse EC	Traverse Electric Cooperative, Inc.
359. Tri-County EC	Tri-County Electric Association, Inc.
360. Tri-State G&T	Tri-State Generation and Transmission Association, Inc.
361. Tucson Power	Tucson Electric Power Company.
362. Turlock	Turlock Irrigation District.
363. Turner-Hutchinson EC	Turner-Hutchinson Electric Cooperative, Inc.
364. TVA	Tennessee Valley Authority.
365. TX Com	Public Utility Commission of Texas.
366. TX Industrials	Texas Industrial Energy Consumers.
367. UAMPS	Utah Associated Municipal Power Systems.
368. Union County EC	Union County Electric Cooperative, Inc.
369. Union Electric	Union Electric Company.
370. United Illuminating	United Illuminating Company.
371. UNITIL	UNITIL Corporation.
372. Urban League	Greater Washington Urban League, Inc.
373. UT Com	Utah Public Service Commission and Utah Division of Public Utilities.
374. UT Industrials	Utah Industrial Energy Consumers (consisting of Alliant Techsystems, Inc., Amoco Oil Company, Holnam, Inc., Kennecott Copper Corp., and Western Zirconium.
375. UtiliCorp	UtiliCorp United Inc.

Abbreviation	Commenter
376. Utilities For Improved Transition	Utilities For an Improved Transition (consisting of Basin Electric Cooperative, Black Hills Corporation, Boston Edison Company, Central Vermont Public Service Corporation, Montaup Electric Company, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation).
377. Utility—Trade Corp. Utility—Trade Corp.	
378. Utility Investors Analysts	Utility Investors and Analysts.
379. Utility Shareholders	United Utility Shareholders Association of America.
380. Utility Wind Interest Group	Utility Wind Interest Group, Inc.
381. Utility Workers Union	Utility Workers Union of America, AFL–CIO.
382. Utility Working Group	Utility Working Group (consisting of Atlantic City Electric Company, Dominion Resources, Inc., Duke Power Company, Florida Power & Light Company, Niagara Mohawk Power Corporation, Pacific Gas and Electric Company, Public Service Electric and Gas Company, and San Diego Gas & Electric Company).
383. VA Com	Staff of the Virginia State Corporation Commission.
384. Vann	Vann, Albert (NY State Assembly).
385. VEPCO	Virginia Electric and Power Company.
386. Verendrye EC	Verendrye Electric Cooperative, Inc.
387. Vernon	City of Vernon, California.
388. VT DPS	Vermont Department of Public Service.
389. WA Com	Washington Utilities and Transportation Commission.
390. Wabash	Wabash Valley Power Association, Inc.
391. WAPA	Western Area Power Administration and Department of Energy.
392. Washington and Oregon Energy Offices	Washington State Energy Office and Oregon Department of Energy.
393. Washington Water Power	Washington Water Power Company Energy Offices.
394. WEPCO	Wisconsin Electric Power Company.
395. West River EC	West River Electric Association, Inc.
396. Western Resources	Western Resources Inc.
397. Whetstone Valley EC	Whetstone Valley Electric Cooperative, Inc.
398. WI Com	Public Service Commission of Wisconsin.
399. Wing Group	Wing Group.
400. Wisconsin Coalition	Wisconsin Coalition (Wisconsin Public Power Incorporated System, Municipal Electric Utilities of Wisconsin, Madison Gas and Electric Company, and Citizens' Utility Board of Wisconsin).
401. Wisconsin EC	Wisconsin Electric Cooperative Association.
402. Wisconsin Municipals	Municipal Electric Utilities of Wisconsin.
403. Wollenberg	Wollenberg, Bruce, et al.
404. Wolverine Coop Members	Wolverine Power Supply Cooperative Special Members Committee.
405. Woodbury County REC	Woodbury County Rural Electric Cooperative.
406. WP&L	Wisconsin Power and Light Company.
407. WSCC	Western Systems Coordinating Council Board of Trustees.
408. WSPP	Western Systems Power Pool.
409. Yellowstone Valley EC	Yellowstone Valley Electric Cooperative, Inc.

Environmental Impact Commenters

1. Attorneys General of Massachusetts, Connecticut, New Jersey and Vermont
2. Center for Clean Air Policy
3. Central Maine Power Company
4. Cincinnati Gas & Electric Company and PSI Energy, Inc.
5. Clifton Below
6. Electric Consumer's Alliance
7. Connecticut Siting Council
8. Southern Environmental Law Center
9. General Public Utilities Corporation
10. Public Advisory Committee of the Grand Canyon Visibility Transport Commission
11. Institute of Clean Air Companies
12. Interstate Natural Gas Association of America
13. Atlantic Electric Co. and Audubon Society of New Hampshire et al.
14. Maryland Department of Natural Resources and Maryland Energy Administration
15. Midwest Ozone Group
16. Missouri Department of Natural Resources
17. National Mining Association, Western Fuels Association, Inc. and the Center for Energy and Economic Efficiency
18. The Navajo Nation
19. Maine, Massachusetts, Vermont and New Hampshire Public Service Commissions
20. New Jersey Board of Public Utilities and the New Jersey Department of Environmental Protection
21. New York State Department of Public Service and the New York State Department of Environmental Conservation
22. Office of the Ohio Consumers' Counsel
23. Ohio Electric Utility Institute Environmental Committee
24. Ozone Transport Assessment Group
25. Ozone Transport Commission
26. Utility Air Regulatory Group (Edison Electric Institute, the National Rural Electric Cooperative Association and the American Public Power Association)
27. Wisconsin Department of Natural Resources

Other (Including Technical Conference Commenters)

1. Electric Power Research Institute
2. Electric Policy Technical Issues Group
3. Tejas Power Corporation
4. Competitive Power Coalition of New England
5. Mid-Continent Area Power Pool
6. Michigan Electric Coordinated Systems
7. Independent Energy Producers Association
8. Praxair, Inc.
9. Utility-Trade Corp.
10. Competitive Power Coalition of New England
11. Wyoming Public Service Commission
12. State of New Jersey
13. Paul Joskow
14. New England Conference of Public Utility Commissioners
15. Commonwealth of Massachusetts
16. Florida Electric Power Coordinating Group
17. Dine Power Authority
18. State of Connecticut Department of Environmental Protection
19. Commonwealth of Massachusetts Department of Environmental Protection
20. State of Maine Department of Environmental Protection
21. Comision Federal de Electricidad of Mexico

Appendix C—Allegations of Public Utilities Exercising Transmission Dominance

I. Examples From Proceedings Before Administrative Law Judges

These are examples of allegations that various public utilities have refused to

provide comparable service, either through refusals to wheel, dilatory tactics that so protracted negotiations as to effectively deny wheeling, refusals to provide service priority equal to native load, or refusals to provide service flexibility equivalent to the utility's own use.

A. American Electric Power Service Corp. (AEP)

In 1993, AEP filed, on behalf of its public utility associate companies, an open access tariff that offered only firm point-to-point service with very limited flexibility. It did not offer network service, flexible point-to-point service, or non-firm service. Thus, it did not provide customers with the same flexibility that AEP itself has. Nor did it provide a service priority equivalent to that enjoyed by native load. The Commission set AEP's tariff for hearing and, on rehearing, held that in order not to be unduly discriminatory, the tariff had to offer comparable service. American Electric Power Service Corp., 64 FERC ¶ 61,279 (1993), *reh'g*, 67 FERC ¶ 61,168 (1994).

At hearing, Raj Rao of Indiana Michigan Power Agency (IMPA) (Ex. IMPA–1, Feb 23, 1994) and Kenneth Hegemann of American Municipal Power-Ohio, Inc. (AMP-Ohio) (Ex. AMPO–1, Feb 23, 1994), both senior management officials, testified concerning AEP's alleged discriminatory practices.[1] AMP-Ohio is an association of municipalities in Ohio, some of whose members depend on AEP for transmission and partial requirements service. IMPA is an association of municipalities in Indiana, and many of IMPA's loads are captive to the AEP transmission system. The witnesses alleged as follows:

1. In anticipation of high peak demands, AEP would contract for large blocks of available short-term power, withhold sale of short-term power, refuse to transmit third party short-term power, and require purchases from AEP at the emergency rate (100 mill/kwh) when an emergency might not exist. Ex. AMPO–1 at 6.

2. In December 1989, AMP-Ohio negotiated a 20 MW purchase of short-term power from Louisville Gas & Electric Company (LG&E). AEP refused to wheel because LG&E had earlier that day told AEP it had no power to sell to AEP. AEP then bought the power from LG&E and offered to resell it to AMP-Ohio. Ex. AMPO–1 at 6–7.

3. In January 1990, AMP-Ohio solicited bids for February power purchases from a number of utilities including AEP. AEP was not the winning bid. AMP-Ohio made arrangements to purchase the power from four winning bidders and sought transmission through AEP. When AMP-Ohio gave AEP the schedule for delivery, AEP refused to transmit the power, matched the average price of the winning bids, and made the sale itself. Ex. AMPO–1 at 7.

4. In August 1993, an AMP-Ohio member (Columbus, Ohio) was purchasing 10 MW of hourly non-displacement power from AEP and, after AEP raised its price to 60 mills/kwh, sought another source for the next hour. Consumers Power Company and Detroit Edison Company both offered non-displacement power at 40 mills. AEP refused to transmit, saying it had a 600 MW unit out and could not resell power from another source.[2] Columbus cancelled the transaction and had to buy 10 MW of power from AEP at 100 mills/kwh. Ex. AMPO–1 at 7–8.

5. In July 1993, two AMP-Ohio members (Columbus and St. Mary's) had been buying hourly non-displacement power from AEP when the price rose to 35 mills. Dayton Power & Light Company (DP&L) offered to sell at 23 mills and AEP agreed to transmit for one hour. But for the next hour, AEP said it had problems with its system, refused to transmit the power, kept the power from DP&L for itself and offered to sell power to AMP-Ohio for Columbus and St. Mary's at 100 mills. Columbus increased its local generation, but St. Mary's purchased 8 MW at 100 mills. For the next hour, AMP-Ohio arranged with DP&L for another 8 MW, hoping AEP would transmit under the 24 hour buy-sell agreement. AEP did transmit this power. Seven hours later in the day, St. Mary's Greenup Hydro project power was available and the 8 MW from DP&L was no longer needed. If St. Mary's had been receiving the hourly power that AEP had refused to transmit, St. Mary's could have switched to Greenup power. But because AMP-Ohio had changed to daily service, St. Mary's had to pay a demand charge for the entire day, even though it used the power only 7 hours and would have paid less under the hourly rate. Ex. AMPO–1 at 8–9.

6. In January 1994, AMP-Ohio sought to transfer power from one member with generation to other members, which required transmission over AEP and Toledo Edison lines. Toledo Edison said yes, AEP said no. AMP-Ohio's northern members purchased emergency power from Toledo Edison. AMP-Ohio then reminded AEP that it had agreed not to deny transmission and AEP agreed to transmit. Ex. AMPO–1 at 9.

7. IMPA arranged to buy 80 MW of short-term power from LG&E and have it wheeled, using buy-sell arrangements, through Public Service Company of Indiana (PSI) and AEP to serve IMPA's load at Richmond (an IMPA member). The delivered price was $.292 per kW-day plus a 1 mill adder. At the same time AEP arranged to buy 300 MW from PSI at $.30 per kW day plus out-of-pocket energy costs. Hence, PSI was shipping a total of 380 MW to AEP with 80 MW of that amount to be delivered to IMPA's load at Richmond. Then, on a day when IMPA should have received the 80 MW, AEP told IMPA that PSI had sold everything to AEP and that IMPA would have to buy from AEP at $.63 per kW day plus the cost of energy from AEP. IMPA purchased from AEP under protest. AEP used its control over transmission to intercept the 80 MW at a lower price and resell it as short-term power to IMPA. AEP claimed that PSI had terminated its sales to AEP on that day. But the 80 MW was independent of PSI's other sales to AEP and would not have been interrupted if AEP had not interrupted it. IMPA–1 at 7.

8. IMPA has combustion turbines owned by and located at one member, which IMPA would like to connect to the Joint Transmission System owned by IMPA, CINergy and Wabash Valley Power Association. To do so, IMPA needed a metering agreement with AEP, to which AEP would not agree. IMPA–1 at 6.

9. In January 1994, IMPA had power to sell from its turbines when AEP and others needed power. IMPA offered power to AEP but AEP it said could not purchase the power without an existing contract. Moreover, since there was no short-term tariff, IMPA could not sell the power to another utility. IMPA–1 at 6.

10. Another example of the utility engaging in dilatory tactics that raised the customer's transaction costs and effectively denied transmission is the ''sham transaction'' provision proposed by AEP. As filed, AEP's tariffs permitted it to deny service merely because a portion of the transmitted power might be used to serve a former retail customer of AEP. *See, e.g.*, Ex. BR&WVP–1 (J. Bertram Solomon testimony, February 23, 1994). (As part of a settlement AEP filed the *pro forma* tariff and withdrew this provision.)

11. Finally, AEP's originally filed tariff contained a ''prodigal customer'' provision. Under this provision, transmission customers who sought to convert back to requirements service had to give AEP five years' notice, in which case AEP and the customer would enter into negotiations to determine whether AEP will provide service at all and if so under what rate, terms, and conditions. Ex. S–39 at 1 (Staff testimony). AEP did not require notice from all new customers, only from prodigal customers. *Id.* at 2. That a potential customer was previously served by AEP is not a reason to treat the customer differently. (AEP withdrew this provision when it filed the *pro forma* tariff.)

B. Entergy Services, Inc. (Entergy)

Entergy filed a partial settlement largely adopting the NOPR *pro forma* tariffs except for two provisions (headroom and ancillary services). Because the settlement predated the filing date for customer testimony before the ALJ, the customers did not address the need for Entergy to file a tariff. However, customers did make allegations of discriminatory practices, as follows.

1. Customers alleged that Entergy flat-out refused to wheel. Louisiana Energy and Power Authority (LEPA) witness Sylvan J. Richard testified that LEPA's predecessor systems could not obtain interconnections from Entergy. Ex. SJR–1 at 50.

2. Customers also alleged that Entergy refused to provide service priority equal to native load and refused to provide service flexibility equivalent to the utility's own use. For example, LEPA witness Richard testified that even after state commissions ordered interconnections and other coordination

[1] After the Rehearing Order expanding the scope of the proceeding, AMP-Ohio and IMPA withdrew this testimony as no longer necessary. This withdrawal does not change the fact that the testimony was sworn to under oath.

[2] AEP generally limited its offer of short-term transmission to buy/sell transactions; that is, AEP would buy the power from the seller and resell it to the purchaser. Supplemental testimony of AEP Witness Baker (Ex. A–73) at 27–29. Often, the terms of the buy/sell transaction required transmission dependent utilities (TDUs) to maintain reserves and meet contractual commitments for at least a year. *Id.*

services, LEPA's predecessors were still not able to obtain coordination services because Entergy was not willing to coordinate and because the transmission service it did offer was inflexible, unidirectional point-to-point service, which prevented economic coordination with others. *Id.* at 50–51.

3. South Mississippi Electric Power Association (SMEPA) witness J. Bertram Solomon testified that Entergy's original ''open access'' tariff was restricted to point-to-point service, proposed separate charges for each operating company, and required the cancellation of existing agreements in order to take service under the proposed tariff. Ex. SMEPA–10 at 28. Entergy eventually filed a network tariff, but proposed different local facilities charges for the various Entergy public utility operating subsidiaries. *Id.* at 29. Since these local facilities charges were higher than the transmission component of the subsidiaries' bundled rates, Entergy obtained a competitive advantage. *Id.*

4. The Arkansas Cities and Cooperatives (ACC) is a group of cities and cooperatives that own or operate electric generation or distribution systems in Arkansas. ACC Witness Steven Merchant testified that Entergy has segregated the wholesale market between two of its subsidiaries, Arkansas Power & Light Copmpany (APL) and Entergy Power, Inc. (EPI). Ex. SMM–1 at 16. In marketing power and energy in Arkansas, EPI is subject to an Arkansas Commission order that bars EPI from competing with APL for wholesale loads without first obtaining a waiver. *Id.* Recently, EPI requested this waiver for all wholesale transactions in Arkansas except for wholesale customers currently served by an Entergy subsidiary; in other words, EPI requested the Arkansas Commission to expand competition for all wholesale customers except where EPI might compete with APL. *Id.* ACC witness Merchant concluded that, since EPI does not compete with APL, Entergy insulates APL's wholesale business from competition and denies those wholesale customers access to EPI as a source of power, thereby limiting alternative generation sources available to ACC. *Id.* at 17–19. (Entergy's witness Kenney stated that Entergy has recently filed a joint motion with ACC to the Arkansas Commission seeking to extend the waiver and permit EPI to sell to APL's wholesale customers. Ex. JFK–11 at 14–15.)

C. Pacific Gas & Electric Company (PG&E)

Northern California Power Agency (NCPA) attached several documents to its 1988 complaint in Docket No. EL89–4. These documents were provided to support NCPA's claim that PG&E's unreasonable practices under the PG&E/NCPA Interconnection Agreement (IA) effectively denied NCPA access to transmission properly requested under the IA. Although the parties eventually settled and the Commission terminated the docket with a letter order dated May 18, 1988, these documents provide allegations of PG&E using dilatory tactics that so protracted negotiations as to effectively equal a refusal to wheel.[3]

1. PG&E stated that since transmission was not currently available, it was entitled to wait 72 months before providing transmission; that is, transmission access could not be granted before the passing of the 72-month notice period. NCPA 1988 Complaint, Ex. 3. However, the IA provided that transmission be provided when it becomes actually available. PG&E also requested substantial additional information, which NCPA considered beyond that reasonably necessary for a study, but still provided. PG&E then determined that transmission was not available, reasoning that transmission was unavailable unless all the transmission requested could be provided 8760 hours per year without restrictions or limitations, extending through the expiration of the agreement in 2013. NCPA 1988 Complaint at 9.

2. On November 27, 1987, NCPA made a new transmission request to PG&E, seeking 50 MW of bi-directional transmission at Midway. NCPA 1988 Complaint, Ex. 5. On January 28, 1988, PG&E filed an interconnection agreement with Turlock Irrigation District (TID) that provided TID with 50 MW of bi-directional transmission at Midway. *Pacific Gas & Electric Company,* 42 FERC ¶ 61,406, *order on reh'g,* 43 FERC ¶ 61,403 (1988). On February 22, 1988, PG&E advised NCPA that all firm transmission service available at Midway had been fully subscribed. NCPA 1988 Complaint, Ex. 6. Then, on March 29, 1988, PG&E filed with the Commission an interconnection agreement with Modesto Irrigation District (MID), that provided MID with 50 MW of bi-directional transmission at Midway. *Pacific Gas & Electric Company,* 44 FERC ¶ 61,010 (1988). At about the same time (in the last week in March 1988), PG&E advised NCPA that the allocations of transmission to TID, MID, and others, including a not yet finalized allocation to Sacramento Municipality Utility District, had used all the transmission available at Midway. NCPA 1988 Complaint, Exs. 7 and 8.

D. Northeast Utilities Service Company (NU)

This is the case where Northeast Utilities acquired Public Service of New Hampshire (PSNH) (Docket No. EC90–10). New England Power Company (NEP) witness Robert Bigelow's direct testimony expressed concern over the ''relatively restrictive transmission policies of both'' NU, on behalf of Northeast Utilities' public utility subsidiaries, and PSNH. Bigelow Direct Testimony at 21 (filed May 25, 1990). In his cross rebuttal testimony, Mr. Bigelow testified that ''NU has a poor track record as a provider of transmission service'' and ''PSNH also has an abhorrent track record as a provider of transmission services.'' Bigelow Cross Rebuttal Testimony, at 3 (filed June 20, 1990). Mr. Bigelow described both NU's and NEP's (his own company) failure to provide service flexibility equivalent to their own use. Except for NEP's TDUs, both NEP and NU historically provided only point-to-point transmission, which required separate scheduling for each transaction. Bigelow Cross Rebuttal at 4.

E. Southern California Edison Company and San Diego Gas and Electric Company

The evidence in this merger proceeding (Docket No. EC89–5) included testimony from a number of witnesses describing instances of Edison's conduct. Richard Greenwalt was the power supply supervisor for the City of Riverside, California. He was responsible for scheduling all purchases of energy for Riverside and for the cities of Azusa, Banning and Colton, California. Greenwalt testimony at 1 (November 1989). (These four cities and Anaheim, California, are collectively referred to as the Southern Cities or Cities.) Joseph Hsu was the Director of Utilities for Azusa. Hsu testimony at 1 (November 1989). Gale Drews was the electric utility director of Colton. Drews testimony at 1–2 (November 1989). Bill Carnahan was the director for Riverside. Carnahan testimony at 1 (November 1989). Gordon Hoyt was the general manager of the Anaheim power department. Hoyt testimony at 1 (November 1989). Dan McCann was the power coordination supervisor for Anaheim. He supervised Anaheim's load scheduling and is a former Edison employee, having worked for Edison for 20 years. McCann Testimony at 1–2 (November 1989). These witnesses testified that Edison refused to wheel as follows.

1. Edison's policy was to curtail the Cities any time it could be justified using any of a list of acceptable reasons to deny interruptible transmission service. *Id.* at 22–23.

2. Edison would not generally provide transmission service when Edison could save money by itself purchasing the economy energy that would be wheeled. McCann testimony at 19. The Cities called Edison every hour to request interruptible transmission service. *Id.* Edison often refused to sell energy available in the Western Systems Power Pool to the Cities and then made available higher cost contract energy or partial requirements service. *Id.* at 19–20.

3. When Anaheim requested Edison provide firm transmission of power from neighboring states, Edison would often agree to provide non-firm service but would not integrate the capacity for many years in the future, saying that its control area did not need capacity at that time. Hoyt testimony at 9. Since the selling utility was interested in a sale of capacity, not just energy, the transaction would not occur. *Id.* Edison repeatedly used its control over transmission to deny Anaheim access to low-cost firm power. *Id.* at 9–10.

4. While Edison provided short-term firm transmission service to the Cities, it would only provide long-term firm service for three specific resources: The SONGS nuclear plant, a specific IPP, and Hoover Dam power. Hoyt testimony at 20. One of Edison's reasons for denying long-term transmission was that Edison desired to reserve the transmission for its own future (unspecified) needs. *Id.*

5. In the 1970s, Edison refused to allow the Cities access to the Pacific Intertie. Hoyt testimony at 21; Drews testimony at 7–8.

[3] All of these incidents are related to and examples of PG&E's conduct described in the NOPR (FERC Stats. & Regs. ¶ 32,514 at 33,073 n.151), that is, the history of PG&E's attempt to avoid its commitments made to the California owners of the California Oregon Transmission Project (COTP). However, these incidents are not exactly the same as the incidents described in the NOPR, because NCPA is not one of the owners of the COTP.

6. In 1988, Edison refused to provide transmission service for a Cities power purchase from Public Service Company of New Mexico (PSNM) from Palo Verde Nuclear station. Hoyt testimony at 21.

7. Edison has refused to provide requested firm transmission from

—California-Oregon border to Midway Station
—Nevada-Oregon Border to Sylmar Substation
—Palo Verde Switchyard to Vista
—SONGS Switchyard to Vista.

Carahan testimony at 15.

8. Riverside requested transmission from Palo Verde and was told that such service was not available. Carnahan testimony at 16. Edison offered Riverside only 12 MW of curtailable transmission entitlement to provide Riverside's share of Palo Verde. *Id.* This service was neither large enough or long enough, and Edison insisted on unreasonable terms and conditions. *Id.*

9. Azusa, Banning and Colton had a contract with Edison that entitled them to use their Palo Verde firm transmission path to schedule energy to meet their contract energy obligation. Edison refused to permit the three cities to use that path. Edison did not contest that the contracts allowed this use, but said that the scheduling of such small amounts of energy for the three cities would be too burdensome. Greenwalt testimony at 14.

10. Edison would not respond in a timely manner to the Cities' requests, routinely taking months to respond. Drews testimony at 15.

11. During the 1980s, Edison provided Colton with some transmission service to allow the Cities to reach certain suppliers, but limited the choices available to the Cities and imposed terms and conditions that increased the Cities' costs and placed Colton at a disadvantage against Edison. Drews testimony at 9. Arranging alternative generation sources was difficult because the Cities always had to first get Edison to state whether it would provide transmission.

12. During 1988 and 1989, a dispute arose between Edison and the Cities concerning the Hoover Uprating Project. Drews testimony at 16. Edison argued that for the months when units were out of service for uprating, and Southern Cities capacity was reduced to zero, Southern Cities would not receive an energy credit, even though energy was still available and used by Edison. But the contracts allowed a participant who did not have capacity to still schedule its energy as non-firm energy on the capacity of another participant. *Id.* at 16–17.

13. In 1986, Azusa negotiated a power purchase contract with the California Department of Water Resources in increments of first 5 MW and then 2 MW (for a total of 7 MW). Hsu testimony at 14. First Edison assured Azusa that the transmission for the additional 2 MW would not be a problem. *Id.* Then Edison would not agree to amend the transmission service agreement for the additional 2 MW. *Id.*

14. In 1986, Azusa notified Edison of Special Condition 12[4] purchases from PG&E and requested firm transmission service. *Id.* Two months before service was to begin, Edison notified the Cities of a problem with the transmission lines. *Id.* Transmission was eventually granted, but only after a four-month delay and substantial losses to the Cities. *Id.* Then Edison decided there was no problem with its transmission facilities. *Id.* at 14–15.

15. In 1986–87, the Cities purchased 20 MW from PG&E and 80 MW from Deseret G&T Cooperative. Hoyt testimony at 7–8. Edison stated that without reinforcement of its transmission system, Edison would not provide the transmission. *Id.* There was a five-month delay during which the Cities were forced to purchase from Edison at a higher cost. *Id.* at 8–9. Then Edison decided that the transmission system did not need reinforcement. *Id.* at 8.

16. Edison also refused to provide a service priority equal to that of native load. It would curtail the Cities in order to purchase more economy energy for itself. McCann testimony at 28. If Edison could make the purchase, it would curtail the City and use the energy for itself. *Id.* When Edison curtailed the Cities, they were not able to purchase economy energy and instead purchased energy from Edison. *Id.* at 24.

17. According to Edison, the interruptible transmission it provided the Cities was interruptible for any reason. *Id.* at 20. A purchase could be terminated the hour after it is begun or even during the hour. *Id.* As a result, the Cities lost opportunities to make advantageous economy purchases. *Id.* at 20–21.

18. Edison also refused to provide customers flexibility similar to the flexibility Edison provided itself. Edison's refusal to provide bi-directional transmission service restricted the Cities' abilities to purchase hydroelectric energy from the Pacific Northwest. Hoyt testimony at 22. Because most contracts with Northwest utilities require a return of power, the Northwest utilities would not deal with the Cities without transmission to return energy. *Id.* at 22–23. Edison did provide bi-directional transmission to the Los Angeles Department of Water & Power (LADWP) to accommodate flows to and from Arizona. *Id.*

19. Riverside was unable to obtain non-firm service more than two hours in advance of need. Carnahan testimony at 18.

20. Riverside and Colton were both served out of Edison's Vista substation. Although the two cities were on the same 69 kV bus, Edison would not allow them to sell energy to each other. Greenwalt testimony at 17.

21. Riverside's agreement with Edison allowed Riverside to purchase a block of energy through the WSPP and divide it up among the four Cities (Azusa, Banning, Colton and Riverside). Greenwalt testimony at 17. When Riverside had excess energy from other sources, Edison would not permit it to sell that energy to the other three cities. *Id.* For example, Riverside attempted to sell Deseret energy transmitted by LADWP to the Edison system. *Id.* at 17–18. LADWP would not break out the Cities' shares of that energy, and Edison would not accept the energy as a delivery for all four cities. *Id.* at 18. Edison argued that because this energy was excess energy that Riverside could not use, Riverside did not have transmission rights to bring it into the control area. *Id.* As a result, Riverside paid for the energy delivered by LADWP to the Edison control area, but could not sell it to the other three cities, and gave it to Edison itself, which consumed the energy without making any payment for it. *Id.* Riverside tried a number of alternative paths, including using WSPP transmission where Riverside paid Edison 5 mills to connect to Azusa, 5 mills to connect to Banning, and 5 mills to connect to Colton for each megawatthour. While this approach was successful for a while, eventually Edison refused to permit these sales.

22. Edison claimed that the Cities only have transmission rights to bring in enough Special Condition 12 energy to satisfy the Cities' load. Greenwalt testimony at 18.

23. Edison contended that the Cities' load requirements were satisfied first by integrated resources and then by Special Condition 12 and economy energy purchases. *Id.* at 19. When the Cities' integrated resources exceeded their load, any Special Condition 12 resources became excess. Under Riverside's Deseret contract, the Cities were required to take a minimum of 35 MW each hour. *Id.* Edison acknowledged that it was obligated to buy, or allow the Cities to sell, any excess energy from Riverside's integrated resources. *Id.* However, Edison refused to give the Cities credit for excess Special Condition 12 energy brought into the area, claiming that the Cities could not have brought it in because they did not have transmission rights. *Id.*

II. Other Examples of Transmission Disputes

Disputes over transmission are not uncommon, contrary to EEI's suggestion. Some recent examples taken from pleadings and other documents and from Commission orders reveal that it has been very difficult for various entities in the electric power industry to agree on transmission rights. These examples also reveal that even after issuance of *AEP* and the Open Access NOPR with its proposed *pro forma* tariffs, there has been considerable controversy over whether various utilities' ''open access'' tariffs deviate from those tariffs. (The Commission has allowed utilities that adopt tariffs that match or exceed the non-rate terms and conditions in the NOPR *pro forma* tariffs to obtain certain benefits.)

A. In a letter of February 3, 1995 to Mr. Gerald Richman of the Commission's Enforcement section in the Office of the General Counsel, Steven J. Kean, Vice President, Regulatory Affairs, Enron Power Marketing, Inc. (Enron) alleged that Niagara Mohawk Power Corporation (NiMo) refused to wheel power from Rochester Gas & Electric (RG&E) to Enron under RG&E's transmission contract with NiMo; however, when Enron revealed the buyer, NiMo did wheel power for RG&E to the buyer. Mr. Kean alleged that this was not an isolated incident. NiMo argued that the contract did not require it to

[4] Special Condition 12 of the Integrated Operations Agreement between Edison and the Southern Cities defined certain Special Condition 12 resources and allowed the Cities to make certain uses of those resources, subject to certain restrictions.

provide RG&E with transmission to Enron. It also said that the principle of comparability does not require the service. Letter of November 21, 1994 from NiMo representative A. Karen Hill to Gerald Richman.

B. The Commission's Task Force Hot Line (Hot Line) received a complaint that a member of the New York Power Pool (NYPP) refused to transmit power that another member bought from a power marketer. In a letter of November 17, 1994, from Chair Moler to Mr. William J. Balet, Executive Director of NYPP, Chair Moler explained that the Commission's enforcement staff had investigated and found the allegation to be true.

C. In *Southern Minnesota Municipal Power Agency* v. *Northern States Power Company (Minnesota),* 73 FERC ¶ 61,350 (1995), NSP and SMMPA had a contract under which NSP agreed to provide transmission service. However, the parties had numerous disputes over the service. The Commission found that NSP had misinterpreted the contract in several ways. For, example, SMMPA argued that it should be able to directly schedule its deliveries of energy out of the NSP control area and that it should not be limited to particular points of delivery. NSP argued that only it was entitled to control the physical operation of scheduling. The Commission found that the clear language of the contracts gave SMMPA the authority to schedule its own power.

D. *Mid-Continent Area Power Pool,* 72 FERC ¶ 61,223 (1995), involved MAPP's membership criteria, which made it impossible for a power marketer to join MAPP and obtain the benefits of certain transmission services available only to MAPP members. The Commission found that the membership criteria may be unreasonable, particularly since there may be less burdensome ways of setting up membership criteria for non-traditional entities.

Appendix D—Pro Forma Open Access Transmission Tariff

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I. Common Service Provisions

1. Definitions

1.1 Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.3 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4 Commission: The Federal Energy Regulatory Commission.

1.5 Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.6 Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.8 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.10 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.11 Eligible Customer: (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale; electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled Transmission Service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Transmission Provider.

1.12 Facilities Study: An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.13 Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.14 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.15 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.16 Load Ratio Share: Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III the Tariff and calculated on a rolling twelve month basis.

1.17 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.18 Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.19 Native Load Customers: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.20 Network Customer: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.21 Network Integration Transmission Service: The transmission service provided under Part III of the Tariff.

1.22 Network Load: The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.23 Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.24 Network Operating Committee: A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.25 Network Resource: Any designated generating resource owned or purchased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.26 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.27 Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.28 Open Access Same-Time Information System (OASIS): The information system and standards of conduct contained in Part 37 of the Commission's regulations.

1.29 Part I: Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II: Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III: Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.33 Point(s) of Delivery: Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement.

1.34 Point(s) of Receipt: Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement.

1.35 Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.37 Receiving Party: The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.38 Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently

coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.39 Reserved Capacity: The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.40 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.41 Service Commencement Date: The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.42 Short-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.43 System Impact Study: An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.44 Third-Party Sale: Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.45 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.46 Transmission Provider: The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.47 Transmission Provider's Monthly Transmission System Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.48 Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.49 Transmission System: The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transmission Capability: For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. If the Transmission Provider offers an affiliate a rate discount, or attributes a discounted Ancillary Service rate to its own transactions, the Transmission Provider must offer at the same time the same discounted Ancillary Service rate to all Eligible Customers. Information regarding any discounted Ancillary Service rates must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation Sources Service: The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR part 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public

Utilities). In the event available transmission capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds: This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide Transmission Service to any Eligible Customer pursuant to this Tariff if the provision of such Transmission Service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such Transmission Service.

5.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act and shall provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer's corporate affiliates. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure: Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues: Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties,

arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and the Transmission Provider involving Transmission Service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under the Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-To-Point Transmission Service

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term: The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority: Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis *i.e.*, in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. After the deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after July 9, 1996, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements: The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Firm Point-To-Point Transmission Service. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, Curtailments will be proportionally allocated among the Transmission Provider's Native Load Customers, Network Customers, and Transmission Customers taking Firm Point-To-Point Transmission Service. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement along with a corresponding capacity reservation associated with each Point of Receipt. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement along with a corresponding capacity reservation associated with each Point of Delivery. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than *10:00 a.m.* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour (or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider). Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to *twenty (20) minutes* (or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider) before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term: Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after July 9, 1996 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements: The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in

the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than *2:00 p.m.* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to *twenty (20) minutes* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service: The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions: The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transmission Capability: A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transmission capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement: If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System: If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

15.5 Deferral of Service: The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers: Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

d. The Transmission Customer agrees to pay for any facilities constructed and

chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

e. The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application: A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit: A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application: Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transmission capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1.

17.6 Execution of Service Agreement: Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service: The Transmission Customer can obtain up to *five (5) one-year extensions* for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved

Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application: Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service: Requests for monthly service shall be submitted *no earlier than sixty (60) days* before service is to commence; requests for weekly service shall be submitted *no earlier than fourteen (14) days* before service is to commence, requests for daily service shall be submitted *no earlier than two (2) days* before service is to commence, and requests for hourly service shall be submitted *no earlier than noon the day* before service is to commence. Requests for service received *later than 2:00 p.m.* prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transmission Capability: Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transmission capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service *(i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.* [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the maximum charge, based on the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the

Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications: Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities: The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service: If the Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an ''Expedited Service Agreement'' pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

20 Procedures if the Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions: When the review process of Section determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions: If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions: The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems

which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement (''Secondary Receipt and Delivery Points''), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service: Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Parties through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service: In accordance with Section 4, Resellers may use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data: The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. Network Integration Transmission Service

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service: Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service: The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service: The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service: The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System.

29 Initiating Service

29.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G.

29.2 Application Procedures: An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection), which shall include, for each Network Resource:

—Unit size and amount of capacity from that unit to be designated as Network Resource
—VAR capability (both leading and lagging) of all generators
—Operating restrictions
—Any periods of restricted operations throughout the year
—Maintenance schedules
—Minimum loading level of unit
—Normal operating level of unit
—Any must-run unit designations required for system reliability or contract reasons
—Approximate variable generating cost ($/MWH) for redispatch computations
—Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource
—Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;

(vi) Description of Eligible Customer's transmission system:

—Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
—Operating restrictions needed for reliability
—Operating guides employed by system operators
—Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
—Location of Network Resources described in subsection (v) above
—10 year projection of system expansions or upgrades
—Transmission System maps that include any proposed expansions or upgrades
—Thermal ratings of Eligible Customer's Control Area ties with other Control Areas; and

(vii) Service Commencement Date and the term of the requested Network Integration

Transmission Service. The minimum term for Network Integration Transmission Service is one year.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities: The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement: The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

Network Resources

30.1 Designation of Network Resources: Network Resources shall include all generation owned or purchased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources: The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made by a request for modification of service pursuant to an Application under Section 29.

30.3 Termination of Network Resources: The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

30.4 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load plus losses.

30.5 Network Customer Redispatch Obligation: As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load Ratio Share.

30.9 Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the planning and operations of the Transmission Provider to serve all of its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider: The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected with the Transmission Provider: This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission

Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (*e.g.* the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates: The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the maximum charge, based on the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

33 Load Shedding and Curtailments

33.1 Procedures: Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints: During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever

actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement.

33.5 Allocation of Curtailments: The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding: To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability: Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load: The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge: The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery: The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation under The Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the [applicable regional reliability council], (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and the [applicable regional reliability council] requirements. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee: A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Schedule 1—Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 2—Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Control Area where the Transmission Provider's transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Schedule 3—Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 4—Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

The Transmission Provider shall establish a deviation band of +/− 1.5 percent (with a minimum of 1 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider. If an energy imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer will compensate the Transmission Provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider. The charges for Energy Imbalance Service are set forth below.

Schedule 5—Operating Reserve—Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 6—Operating Reserve—Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 7—Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

(1) Yearly delivery: one-twelfth of the demand charge of $_____/KW of Reserved Capacity per year.

(2) Monthly delivery: $_____/KW of Reserved Capacity per month.

(3) Weekly delivery: $_____/KW of Reserved Capacity per week.

(4) Daily delivery: $_____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(5) Discounts: If the Transmission Provider offers an affiliate a rate discount or attributes a discounted transmission rate to its own

transactions, the Transmission Provider must offer at the same time the same discounted Firm Point-To-Point Transmission Service rate to all Eligible Customers on the same path and on all unconstrained transmission paths. Information regarding any firm transmission discounts must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner.

Schedule 8—Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

(1) Monthly delivery: $_____/KW of Reserved Capacity per month.

(2) Weekly delivery: $_____/KW of Reserved Capacity per week.

(3) Daily delivery: $_____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $_____/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(5) Discounts: If the Transmission Provider offers an affiliate a rate discount or attributes a discounted transmission rate to its own transactions, the Transmission Provider must offer at the same time the same discounted Non-Firm Point-To-Point Transmission Service rate to all Eligible Customers on the same path and on all unconstrained transmission paths. Information regarding any non-firm transmission discounts must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner.

Attachment A—Form Of Service Agreement for Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between _____ (the Transmission Provider), and _____ (''Transmission Customer'').

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in the amount of $_____, in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on _____.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

_____

_____

Transmission Customer:

_____

_____

7.0 The Tariff is incorporated herein and made a part hereof.

In Witness Whereof, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: _____

Name

_____

Title

_____

Date

_____

_____

Transmission Customer:

By: _____

Name

_____

Title

_____

Date

_____

_____

Specifications for Firm Point-To-Point Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates. _____

_____

3.0 Point(s) of Receipt: _____

Delivering Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of capacity and energy to be transmitted _____

(Reserved Capacity): _____

6.0 Designation of party(ies) subject to reciprocal service obligation: _____

7.0 Name(s) of any Intervening Systems providing transmission service: _____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: _____

8.2 System Impact and/or Facilities Study Charge(s): _____

8.3 Direct Assignment Facilities Charge: __

_____

8.4 Ancillary Services Charges: _____

Attachment B—Form Of Service Agreement For Non-Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between _____, (the Transmission Provider), and _____, (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

_____

Transmission Customer:

_____

7.0 The Tariff is incorporated herein and made a part hereof.

In Witness Whereof, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

_____

By: _____

_____

_____

Name

_____

Title

_____

Date

Transmission Customer:

_____

By: _____

_____

_____

Name

_____

Title

_____

Date

Attachment C—Methodology To Assess Available Transmission Capability

To be filed by the Transmission Provider.

Attachment D—Methodology for Completing a System Impact Study

To be filed by the Transmission Provider.

Attachment E—Index Of Point-To-Point Transmission Service Customers

Customer _____
Date of Service Agreement _____

Attachment F—Service Agreement for Network Integration Transmission Service

To be filed by the Transmission Provider.

Attachment G—Network Operating Agreement

To be filed by the Transmission Provider.

Attachment H—Annual Transmission Revenue Requirement for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be _____.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Attachment I—Index of Network Integration Transmission Service Customers

Customer _____
Date of Service Agreement _____

Appendix E—Group 1 Public Utilities

Alabama Power Company
Appalachian Power Company
Arkansas Power & Light Company
Atlantic City Electric Company
Baltimore Gas & Electric Company
Black Hills Power & Light Company
Cambridge Electric Light Company
Central Illinois Light Company
Central Power and Light Company
Central Vermont Public Service Corporation
Cheyenne Light, Fuel and Power Company
Cincinnatti Gas & Electric Company
Citizens Utilities Company
Columbus Southern Power Company
Commonwealth Edison Company
Commonwealth Electric Company
Connecticut Light & Power Company
Connecticut Valley Electric Company
Consumers Power Company
Dayton Power & Light Company
Delmarva Power & Light Company
Duke Power Company
Duquesne Light Company
Florida Power & Light Company
Florida Power Corporation
Georgia Power Company
Granite State Electric Company
Gulf Power Company
Gulf States Utilities Company
Holyoke Power & Electric Company
Holyoke Water Power Company
Idaho Power Company
IES Utilities, Inc.
Illinois Power Company
Indiana Michigan Power Company
Interstate Power Company
Jersey Central Power & Light Company
Kansas City Power & Light Company
Kansas Gas & Electric Company
Kentucky Power Company
Kentucky Utilities Company
Kingsport Power Company
Louisiana Power & Light Company
Louisville Gas & Electric Company
Maine Public Service Company
Massachusetts Electric Company
Metropolitan Edison Company
MidAmerican Energy Company
Midwest Energy, Inc.
Minnesota Power & Light Company
Mississippi Power Company
Mississippi Power & Light Company
Monongahela Power Company
Montana Power Company
Montaup Electric Company
Nantahala Power & Light Company
Narragansett Electric Company
Nevada Power Company
New England Power Company
New Orleans Public Service Inc.
Northern Indiana Public Service Company
Northern States Power Company(Wisconsin)
Northern States Power Company (Minnesota)
Ohio Power Company
Orange & Rockland Utilities, Inc.
Pacific Gas & Electric Company
PacifiCorp
PECO Energy Company
Pennsylvania Electric Company
Pennsylvania Power & Light Company
Pike County Light & Power Company
Portland General Electric Company
Potomac Edison Company
Potomac Electric Power Company
PSI Energy, Inc.
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Company of New Hampshire
Public Service Electric and Gas Company
Public Utility Company of Oklahoma
Puget Sound Power & Light Company
Rockland Electric Company
San Diego Gas & Electric Company
Savannah Electric and Power Company
South Carolina Electric & Gas Company
Southern California Edison Company
Southern Indiana Gas & Electric Company
Southwestern Electric Power Company
Southwestern Public Service Company
Tampa Electric Company
United Illiminating Company
UtiliCorp United, Inc.
Washington Water Power Company
West Penn Power Company
West Texas Utilities Company
Western Massachusetts Electric Company
Western Resources, Inc.
Wheeling Power Company
Wisconsin Electric Power Company
Wisconsin Power & Light Company
Wisconsin Public Service Corporation

Note: Transmission tariffs have also been filed for some public utilities associated with pending merger applications. These individual utilities are not included in Group 1 and will be required to file tariffs on compliance with the Final Rule. They are: Centerior's filing for Cleveland Electric Illuminating Company and Toledo Edison Company; Interstate Energy Corporation's filing for South Beloit Water, Gas & Electric Company; Resources West's for Sierra Pacific Power Company; and the rate filing associated with the merger of Union Electric Company and Central Illinois Public Service Company.

Appendix F—Group 2 Public Utilities

Arizona Public Service Company
Bangor Hydro-Electric Company
Blackstone Valley Electric Company
Boston Edison Company
Carolina Power & Light Company
Central Hudson Gas & Electric Corporation
Central Illinois Public Service Company
Central Louisiana Electric Company, Inc.
Central Maine Power Company
Cleveland Electric Illuminating Company
Commonwealth Edison Company of Indiana
Concord Electric Company
Consolidated Edison Company of New York Inc.
Consolidated Water Power Company
Detroit Edison Company
Eastern Edison Company
Edison Sault Electric Company
El Paso Electric Company
Electric Energy Inc.
Empire District Electric Company
Exeter & Hampton Electric Company
Fitchburg Gas & Electric Light Company
Green Mountain Power Corporation
Indiana-Kentucky Electric Corporation
Indianapolis Power & Light Company
Kanawha Valley Power Company
Lockhart Power Company
Long Island Lighting Company
Long Sault, Inc.
Madison Gas & Electric Company
MDU Resources Group, Inc.
Mt. Carmel Public Utility Company
New England Electric Transmission Corporation
New England Hydro Transmission Electric Company
New England Hydro Transmission Corporation
New York State Electric & Gas Corporation
Newport Electric Corporation
Niagara Mohawk Power Corporation
Northwestern Public Service Company
Northwestern Wisconsin Electric Company
Ohio Edison Company
Ohio Valley Electic Corporation
Oklahoma Gas & Electric Company
Old Dominion Electric Cooperative
Otter Tail Power Company
Pennsylvania Power Company
Peoples Electric Cooperative
Rayburn Country Electric Cooperative
Rochester Gas & Electric Corporation
Sierra Pacific Power Company
South Beloit Water, Gas & Electric Company
St. Joseph Light & Power Company
Superior Water, Light and Power Company
Texas-New Mexico Power Company
Toledo Edison Company
Tucson Electric Power Company
UGI Utilities, Inc.
Union Electric Company
Union Light, Heat & Power Company
Unitil Power Corporation
Upper Penninsula Power Company
Vermont Electric Transmission Company
Vermont Electric Power Company
Virginia Electric & Power Company
Yadkin, Inc.

Appendix G

I. Legal Analysis of Commission Jurisdiction Over the Rates, Terms and Conditions of Unbundled Retail Transmission in Interstate Commerce

Based on an analysis of the relevant legislative history and case law under the Federal Power Act (FPA), the Commission concludes that it has exclusive jurisdiction over the rates, terms and conditions of the unbundled transmission in interstate commerce, by a public utility, of electric energy to an end user. This is also known as retail wheeling in interstate commerce. [1]

The Commission's jurisdiction over the rates, terms and conditions of transmission in interstate commerce derives from Congress' power to regulate interstate commerce under the United States Constitution [2] and the FPA. When Congress enacted the FPA, it gave the Commission exclusive jurisdiction over the rates, terms and conditions of transmission in interstate commerce by public utilities. The Supremacy Clause of the Constitution provides that federal laws enacted pursuant to the powers delegated to the federal government by the United States Constitution are the supreme law of the land.[3] Accordingly, to the extent that retail wheeling involves transmission in interstate commerce by public utilities, the rates, terms and conditions of such service are subject to the exclusive jurisdiction of the Commission, and must be filed with the Commission.[4]

1. Relevant Federal Power Act Provisions

Section 201(b)(1) of the FPA provides:

The provisions of this Part shall apply to *the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce* * * *. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction * * * over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

16 U.S.C. 824(b)(1) (emphasis added). Thus, the statute on its face limits Commission jurisdiction over sales of energy to sales at wholesale, but does not limit jurisdiction over transmission to transmission used only for wholesale sales.

Sections 201 (c) and (d) define the meaning of ''the transmission of electric energy in interstate commerce'' and ''sale of electric energy at wholesale in interstate commerce.'' Section 201(c) provides:

For the purpose of this Part, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof: but only insofar as such transmission takes place within the United States.

16 U.S.C. 824(c). Section 201(d) provides:

The term ''sale of electric energy at wholesale'' when used in this Part means a sale of electric energy to any person for resale.

16 U.S.C. 824(d).

Sections 205 and 206 of the FPA give the Commission jurisdiction over the rates, terms and conditions of transmission in interstate commerce, and sales at wholesale in interstate commerce, by public utilities. 16 U.S.C. 824d and 824e.

2. Legislative History and Case Law

Much of the legislative history of the FPA indicates that Congress intended the Commission's jurisdiction to extend only to those matters which the *Attleboro* decision [5] held to be beyond the reach of the States. For instance, the report accompanying the Senate bill states that subsection (b) ''leaves to the States the authority to fix local rates even in cases where the energy is brought in from another State.'' [6] In other words, states retain authority to regulate rates of electric energy to ultimate consumers. The Senate report also states:

The rate-making powers of the Commission are confined to those wholesale transactions which the Supreme Court held in (*Attleboro*) to be beyond the reach of the States. *Jurisdiction is asserted also over all interstate transmission lines whether or not there is sale of the energy carried by those lines* and over the generating facilities which produce energy [7] for interstate transmission and sale. S. Rep. No. 621, 74th Cong., 1st Sess. 48 (1935) (emphasis added). Thus, federal jurisdiction over transmission lines is not dependent on whether those lines are used to effect a sale, wholesale or otherwise.

The provisions of FPA section 201 reserving certain regulatory authority to the States have been interpreted narrowly.[8] The Supreme Court has stated:

In section 201(b), Congress did no more than leave standing whatever valid state laws then existed relating to the exportation of hydroelectric energy; by its plain terms, section 201(b) simply saves from pre-emption under Part II of the Federal Power Act such state authority as was otherwise ''lawful.'' [9]

The Court also stated:

Nothing in the legislative history or language of the statute evinces a congressional intent 'to alter the limits of state power otherwise imposed by the Commerce Clause,' * * * or to modify the earlier holding of this Court concerning the limits of state authority to restrain interstate trade.[10]

Unlike the narrow interpretations given to the FPA provisions reserving certain regulatory authority to the States,[11] the courts have construed transmission ''in interstate commerce'' broadly. The term does not turn on whether the contract path for a particular power or transmission sale crosses state lines, but rather follows the physical flow of electricity. Because of the highly integrated nature of the electric system, this results in most transmission of electric energy being ''in interstate commerce.''

One of the earliest cases construing Commission jurisdiction over transmission was *Jersey Central Power & Light Co.* v. *FPC*, 319 U.S. 61 (1943) (*Jersey Central*). In that case, the Commission asserted jurisdiction over a New Jersey utility by showing that the utility owned transmission facilities that were used to transmit energy in interstate commerce. The Court found that the Commission had demonstrated that the utility owned transmission facilities that were indirectly interconnected, through a second New Jersey utility, to facilities owned by a New York utility and that the facilities were used to transmit electric energy in interstate commerce.

The Court noted that section 201(c) of the FPA defines electric energy transmitted in interstate commerce to be energy ''transmitted from a State and consumed at any point outside thereof.'' The Court stated:

It is impossible for us to conclude that this definition [of transmission in interstate commerce] means less than it says and applies only to the energy at the instant it crosses the state line and so only to the facilities which cross the line and only to the company which owns the facilities that cross the line.

319 U.S. at 71. Thus, a critical question regarding the jurisdictional status of a wheeling transaction is whether the facilities used to provide the service transmit electric energy in interstate commerce.

[1] Section 212(h) of the FPA provides that no order issued under the FPA shall be conditioned upon or require the transmission of electric energy directly to an ultimate consumer. 16 U.S.C. 824k(h). The Commission's assertion of jurisdiction in this final rule is over the rates, terms and conditions of retail transmission that occurs voluntarily or as a result of a state retail access program.

[2] U.S. Const. art I, Section 8, cl.3.

[3] U.S. Const. art. VI, cl.2.

[4] *See* Montana-Dakota Utilities Co. v. Northwestern Public Service Co., 341 U.S. 246, 251–52 (1951) (*Montana-Dakota*).

[5] Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927) (*Attleboro*). In *Attleboro*, the Supreme Court held that State regulation of the interstate sale of electricity was barred by the Commerce Clause because such regulation would impose a ''direct burden'' on interstate commerce.

[6] S. Rep. No. 621, 74th Cong., 1st Sess. 48 (1935). *See also* H.R. Rep. No. 1318, 74th Cong., 1st Sess. 8 (1935).

[7] The provisions of the Senate bill regarding federal jurisdiction over generating facilities were eliminated from the final version of the bill.

[8] Section 201(a) declares that Federal regulation of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, ''such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.'' 16 U.S.C. 824(a). Section 201(b)(1) states that the provisions of Part II of the FPA apply to the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce but, except as specifically provided, ''shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line.'' 16 U.S.C. 824(b)(1).

[9] New England Power Co. v. New Hampshire, 455 U.S. 331, 341 (1982) (*NEPCO*).

[10] *Id.* (citation omitted).

[11] While Congress may exercise its Commerce Clause authority to grant the States that ''ability to restrict the flow of interstate commerce that they would not otherwise enjoy,'' Lewis v. BT Investment Managers, Inc., 447 U.S. 27, 44 (1980), States may not exercise such regulatory powers unless Congress has expressly stated its intention to make such an affirmative grant of power. *NEPCO*, 455 U.S. at 343.

In *Connecticut Light & Power Co.* v. *FPC,* 324 U.S. 515 (1945) (*CL&P*), the Court reviewed the Commission's finding that a Connecticut utility was jurisdictional because it owned transmission facilities that were used in interstate commerce. The Court generally embraced the *Jersey Central* standard for determining whether facilities are used to transmit electric energy in interstate commerce. The Court emphasized that whether certain facilities transmit electric energy in interstate commerce is more a technical than a legal question. The Court stated:

Federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.

324 U.S. at 529. Thus, the Court adopted the *Jersey Central* test providing that the Commission's jurisdiction generally extends to transmission facilities that transmit electric energy in interstate commerce.

The Court also applied the *Jersey Central* test in *FPC* v. *Florida Power & Light Co.,* 404 U.S. 453 (1972), affirming the Commission's finding of jurisdiction over a Florida utility. The Commission demonstrated that the utility transmitted power to another Florida utility's ''bus'' [12] and that power was simultaneously transferred from the ''bus'' to a Georgia utility. The Court upheld the Commission's finding that electric energy from the two Florida utilities was commingled and was therefore transmitted in interstate commerce. 404 U.S. at 463.

In all of the above cases, the Court's decisions turned on whether energy being transmitted flowed in interstate commerce as a technical matter. The decisions did not turn on whether the transmission of energy flowing in interstate commerce involved energy that was being sold for resale or was being sold to an end user. Thus, there is nothing in the statute, its legislative history, or the case law to indicate that the Commission's jurisdiction over rates, terms and conditions of transmission in interstate commerce extends only to wholesale transmission and not retail transmission. Indeed, the statute on its face gives the Commission jurisdiction over transmission in interstate commerce and makes no distinction between wholesale transmission and retail transmission.

However, there are two important limitations on Commission authority. First, as discussed above, the FPA does not give the Commission jurisdiction over sales of electric energy at retail. Such sales historically have been bundled sales (*i.e.,* generation and transmission), and courts and the Commission have recognized State jurisdiction over bundled sales of energy. Second, under section 201(b)(1) of the FPA, the Commission does not have jurisdiction over facilities used in local distribution. In *CL&P,* the Court stated that local distribution facilities are exempt from Commission jurisdiction even if those facilities ''carry no energy except extra-state energy.'' 324 U.S. at 531.

In the next section the Commission further discusses the statutory provisions and case law that shed light on the demarcation between transmission and local distribution, and thus on the jurisdictional line between federal and State authority.

II. Legal Analysis of Commission Jurisdictional Transmission Facilities and State Jurisdictional Local Distribution Facilities

Two specific circumstances are addressed:

First, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

Second, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to an end user?

Based on an analysis of the relevant legislative history and case law under the FPA, the Commission reaches the following conclusions. With respect to the first circumstance, the Commission concludes that a public utility's facilities used to deliver electric energy to a wholesale purchaser, whether labeled ''transmission,'' ''distribution,'' or ''local distribution'' are subject to the Commission's exclusive jurisdiction under sections 205 and 206 of the FPA, and that a public utility's facilities used to deliver electric energy from the wholesale purchaser to the ultimate consumer are ''local distribution'' facilities subject to the rate jurisdiction of the state. [13]

With respect to the second circumstance, the Commission believes that, based on the particular facts of the case, some of the public utility's facilities used to deliver electric energy to an end-user may be FERC-jurisdictional transmission facilities, while some of the facilities used may be state-jurisdictional local distribution facilities.

We set forth below the relevant legislative history and case law, our legal conclusions, and the factors which we believe are indicative of whether facilities are used in ''local distribution'' or ''transmission in interstate commerce,'' as those terms are used in the FPA.

1. Relevant Federal Power Act Provisions

The Commission's jurisdiction is set forth in section 201 of the FPA. [14] Section 201(b)(1) provides in pertinent part:

The provisions of this Part shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce * * *. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction * * * over *facilities used in local distribution* or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[15]

Some of the court decisions that construe jurisdictional facilities under section 201 also construe the Commission's jurisdiction under section 203. Section 203(a) provides, in relevant part:

No public utility shall sell, lease, or otherwise dispose of the whole of its *facilities subject to the jurisdiction of the Commission,* * * * or by any means whatsoever, directly or indirectly, merge or consolidate such facilities or any part thereof with those of any other person * * * without first having secured an order of the Commission to do so.[16]

In addition, section 206(d) concerns facilities ''under the jurisdiction of the Commission'':

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of *facilities under the jurisdiction of the Commission* in cases where the Commission has no authority to establish a rate governing the sale of such energy.[17]

2. Legislative History of the FPA

The relevant legislative history of the general purposes of Title II of the FPA, and of section 201 in particular, focuses primarily on bundled sales of electric energy and does not directly address the issue of what constitutes local distribution as opposed to transmission in interstate commerce.

In discussing the general purposes of Title II of the House bill, the House Report states:

Title II * * * establishes for the first time regulation of electric utility companies transmitting energy in interstate commerce.

* * * * *

* * * Under the decision of the Supreme Court of the United States in (Attleboro), the rates charged in interstate wholesale transactions may not be regulated by the States. Part II gives the Federal Power Commission jurisdiction to regulate these rates. A ''wholesale'' transaction is defined to mean the sale of electric energy for resale and the Commission is given no jurisdiction over local rates even where the electric energy moves in interstate commerce.[18]

In its analysis of section 201, the House Report states:

As in the Senate bill no jurisdiction is given over local distribution of electric energy, and the authority of States to fix local rates is not disturbed even in those cases where the energy is brought in from another State.[19]

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[12] A bus is an electrical conductor which serves as a common connection for two or more electrical circuits. Electric Utility Rate Design Study, Glossary: Electric Utility and Ratemaking Load & Management Terms, Edison Electric Institute (Sept. 11, 1978).

[13] There are, of course, facilities that are used to provide delivery to both wholesale purchasers and end users. In those situations, we believe that the Commission and the States have jurisdiction to set rates for the services that are within their respective jurisdictions. That facilities are used to serve resale and retail customers does not, however, necessarily mean that the facilities are local distribution facilities.

[14] 16 U.S.C. 824.

[15] 16 U.S.C. 824(b) (emphasis added).

[16] 16 U.S.C. 824b (emphasis added).

[17] 16 U.S.C. 824e(d) (emphasis added).

[18] H.R. Rep. No. 1318, 74th Cong., 1st Sess. 7–8 (1935).

[19] *Id.* at 27.

The Senate Report's discussion of the general purposes of the FPA states:

The decision of the Supreme Court in (*Attleboro*) placed the interstate wholesale transactions of the electric utilities entirely beyond the reach of the States. Other features of this interstate utility business are equally immune from State control either legally or practically.[20]

In discussing material differences between the final version of the Senate bill and the original version, the Senate Report states:

Subsection (b), formerly (a), which states the subject matter to which the part relates, has been clarified to make plain that it includes interstate transmission where there is no sale and excludes all facilities used only for production of transmission in intrastate commerce or in local distribution.[21]

In discussing section 201 of the Senate bill, the Senate Report further states:

The rate-making powers of the Commission are confined to those wholesale transactions which the Supreme Court held in (*Attleboro*) to be beyond the reach of the States. Jurisdiction is asserted also over all interstate transmission lines whether or not there is sale of the energy carried by those lines and over the generating facilities which produce energy for interstate transmission and sale. It is obvious that no steps can be taken to secure the planned coordination of this industry on a regional scale unless all of the facilities, other than those used solely for retail distribution, are made subject to the jurisdiction of the Commission. Facilities used only for intrastate commerce or local distribution are expressly excluded from the operation of the act.[22]

The Conference Report adds little description regarding jurisdictional facilities. In reference to section 201(b) it states that:

[T]he language of the House amendment has been followed with a clarifying phrase added to remove any doubt as to the Commission's jurisdiction over facilities used for the generation and local distribution of electric energy to the extent provided in other sections of this part and the part next following.[23]

In addition to the above statements pertaining to section 201 of the FPA, Congress referenced distribution of energy in the legislative history of section 206(d). Section 206(d) was originally enacted as section 206(b) of the FPA. Under the Regulatory Fairness Act of 1988,[24] section 206(b) was redesignated as section 206(d).

The Conference Report on the original FPA does not address section 206(b). The Senate Report on the FPA bill states in pertinent part:

Subsection (b) authorizes the Commission to investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy. * * * Since the rate-making powers granted to the Commission apply only to the wholesale rates of energy sold in interstate commerce, this last subsection should be of great benefit in removing the practical difficulty which the States may encounter in regulating the *interstate distribution rates* which are left under their control. Such rate regulation involves the examination and valuation of property *outside* the State. The task is one requiring an agency with a jurisdiction broader than that of a single State. The authority of the Federal Commission is to render assistance to the State commissions in a way which would preserve and make more effective the jurisdiction which is thus left to the States.[25]

The House Report discusses section 206(b) as follows:

This subsection reaches those situations where electric energy is transmitted in interstate commerce *by the same company which distributes it locally*, and will greatly aid State commissions in fixing reasonable rates in such cases.[26]

Thus, the discussions in the two reports do not appear to contemplate a situation in which the transmitter and seller of electric energy are different, and neither is a ''local'' distributor. The House Report expressly refers to the same company being the transmitter and seller of electric energy. The Senate Report by its terms addresses the regulation of interstate distribution rates.[27]

The above legislative history on sections 201 and 206(b) does not provide any definitive answers to the questions raised. We therefore turn to the case law under the FPA.

3. Case Law Under the FPA

Jersey Central was the first of the major FPC jurisdictional cases considered by the Supreme Court. The case involved the acquisition by New Jersey Power and Light Company (New Jersey Power) of certain securities of Jersey Central Power & Light Company (Jersey Central) without the Commission's prior approval. The question before the Court was whether Jersey Central was a ''public utility'' under section 201(e)[28] of the FPA so that the Commission's prior approval of the stock acquisition was necessary under section 203 of the FPA.

Jersey Central owned transmission facilities that connected to facilities that Public Service Electric & Gas Company (Public Service) owned. The interconnection of these transmission facilities was in New Jersey. Public Service's facilities in turn connected to the facilities of the Staten Island Edison Corporation (Staten Island Edison), a New York utility, at the mid-channel of Kill van Kull, a body of water separating New Jersey and New York. Jersey Central delivered energy to and received energy from Public Service under contract, and Public Service delivered energy to and received energy from Staten Island Edison under contract.[29]

The Court found that, although Jersey Central generated and received electricity only in New Jersey, some of the electric energy that it dispatched to Public Service ''was instantaneously transmitted to New York.''[30] The Court held that ''[t]his evidence * * * furnishes substantial basis for the conclusion of the Commission that facilities of Jersey Central are utilized for the transmission of electric energy across state lines.''[31] Therefore, the Court found that Jersey Central was a public utility within the meaning of section 201(e).[32]

The Court cited *Attleboro*, in which the Court found that the sale of locally produced electric energy for use in another state resulted in the transmission of electric energy in interstate commerce, even though title passed at the state line.[33] In *Jersey Central*, the Court explained the rationale for federal jurisdiction as follows:

(Section 201(c) of the FPA) defines the electric energy in commerce as that ''transmitted from a State and consumed at any point outside thereof.'' There was no change in this definition in the various drafts of the bill. The definition was used to ''lend precision to the scope of the bill.'' It is impossible for us to conclude that this definition means less than it says * * *. The purpose of this act was primarily to regulate the rates and charges of the interstate energy.[34]

The Court in *Jersey Central* thus interpreted the FPA as placing within the federal province regulation of wholesale sales of electric energy that, in any manner, flows in interstate commerce. The language quoted above and the citation to section 201(c) of the FPA, to be relied upon in subsequent Supreme Court cases, strongly suggested that the Commission's jurisdiction was not based on whether there was a sale by the utility, but rather on the flow of electric energy either into or out of a state, so long as the energy crosses state lines.

CL&P, which was decided two years after *Jersey Central*, is the leading case interpreting

[20] S. Rep. No. 621, 74th Cong., 1st Sess. at 17 (1935). *See id.* at 18 (''The revision [between the original and final versions of the Senate bill] has also removed every encroachment upon the authority of the States. The revised bill would impose Federal regulation only over those matters which cannot effectively be controlled by the States.'')

[21] *Id.* at 19.

[22] *Id.* at 48. The provisions of the Senate bill regarding federal jurisdiction over generating facilities were eliminated from the final version of the bill.

[23] H.R. Conf. Rep. No. 1903, 74th Cong., 1st Sess. 74 (1935).

[24] Pub. L. No. 100–473, 102 Stat. 2299 (1988).

[25] S. Rep. No. 621, 74th Cong., 1st Sess. 51 (1935) (emphasis added).

[26] H.R. Rep. No. 1318, 74th Cong., 1st Sess. 29 (1935) (emphasis added).

[27] The Senate Report states that interstate distribution rates are left in the States' control. Obviously, the Senate drew a distinction between interstate distribution (left in the States' control) and interstate transmission (given to the FPC). *Compare* S. Rep. No. 621 at 49 *with* H.R. Rep. No. 1318 at 51.

[28] Section 201(e) defines a ''public utility'' as ''any person who owns or operates facilities subject to the jurisdiction under this Part (other than facilities subject to such jurisdiction solely by reason of section 210, 211, or 212).'' 16 U.S.C. 824(e). The section as adopted in 1935 did not contain the parenthetical, which was adopted in 1978 as part of the Public Utility Regulatory Policies Act.

[29] *Jersey Central*, 319 U.S. at 63–65.

[30] *Id.* at 66.

[31] *Id.* at 67 (citation omitted).

[32] *Id.* at 73.

[33] 273 U.S. at 86, 89–90.

[34] 319 U.S. at 71 (footnote omitted).

the section 201(b) local distribution proviso. In *CL&P*, the Commission sought to regulate the accounting practices of Connecticut Light & Power Company (CL&P).[35] At issue was whether CL&P was a ''public utility'' under the FPA. The utility's system encompassed an area solely within a single state (Connecticut)[36] and did not interconnect with any other company that operated out of state.[37] ''Its purchases and sales, its receipts and deliveries of power, (were) all within the state.''[38] However, CL&P did purchase energy from companies that had, in turn, purchased energy from Massachusetts. The company also sold energy to a municipality that exported a portion of that energy to Fishers Island, located off the coast of Connecticut but ''territory of New York.''[39] The Commission based its jurisdiction on these few transactions.[40]

The Court of Appeals affirmed the Commission, holding that the Commission's jurisdiction extended to ''electric distribution systems which normally would operate as interstate businesses.'' The Court of Appeals found that:

Whether or not the facilities by which petitioner distributes energy from Massachusetts should be classified as 'local' is not relevant to this case. The sole test of jurisdiction of the Commission over accounts is whether these facilities, 'local' or otherwise, are used for the transmission of electric energy from a point in one state to a point in another.([41])

The Supreme Court reversed. It held that the statutory language in section 201(b) of the FPA providing that the Commission ''shall not have jurisdiction * * * over facilities used in local distribution'' is a limitation upon Commission jurisdiction that ''the Commission must observe and the courts must enforce.''[42] In analyzing the statute, the Court stated:

It has never been questioned that technologically generation, transmission, distribution and consumption are so fused and interdependent that the whole enterprise is within the reach of the commerce power of Congress, either on the basis that it is, or that it affects, interstate commerce, if at any point it crosses a state line.

* * * * *

But whatever reason or combination of reasons led Congress to put the provision in the Act, we think it meant what it said by the words ''but shall not have jurisdiction * * * over facilities used in local distribution.'' Congress by these terms plainly was trying to reconcile the claims of federal and local authorities and to apportion federal and state jurisdiction over the industry.[43]

The Court decided that this limitation on jurisdiction was ''a legal standard that must be given effect in this case in addition to the technological transmission test.''[44]

The Court stated that whether or not local distribution facilities carried out-of-state electric energy was irrelevant. Whatever the origin of the electric energy they carried, so long as the utility used the lines for local distribution,[45] they were exempt from federal jurisdiction.[46] In fact, the Court stated that local distribution facilities ''may carry no energy except extra-state energy and still be exempt under the Act.'' *Id.* at 531. The Court concluded that the Commission's order:

Must stand or fall on whether this company owned facilities that were used in transmission of interstate power and which were not facilities used in local distribution.[47]

Upon reversing the Court of Appeals, the Court commented, in dictum, on the evidence the Commission had relied upon in finding that the facilities in question were used for transmission. It noted that the Commission had relied upon certain gas transportation cases in concluding that transmission extends from the generator to the point where the function of conveyance in bulk over distance is completed and the process of subdividing the energy to serve ultimate consumers, which is the characteristic of ''local distribution,'' is begun. The Court cautioned:

But a holding that distributing gas at low pressure to consumers is a local business is not a holding that the process of reducing it from high to low pressure is not also part of such local business. In so far as the Commission found in these cases a rule of law which excluded from the business of local distribution the process of reducing energy from high to low voltage in subdividing it to serve ultimate consumers, the Commission has misread the decisions of this Court. No such rule of law has been laid down.[48]

The Court also noted in its dictum, however, that once a company is properly found to be a ''public utility'' under the Act, the fact that a local commission may also have jurisdiction does not preclude exercise of the Commission's functions. *Id.* at 533.[49]

The Court instructed the lower court to remand the case to the Commission for a finding regarding whether the facilities in question were used in local distribution.[50]

The *CL&P* case was ultimately disposed of without the Commission having made a finding that the facilities were used in local distribution. While the Commission found that it was ''extremely doubtful'' that it could find that the facilities in question were not local distribution facilities, 6 FPC 104, 106 (1947), the Commission did not articulate a definition of local distribution facilities.

In *Wisconsin-Michigan Power Co.* v. *Federal Power Commission*,[51] the Seventh Circuit held that a utility was a jurisdictional public utility where it operated two divisions in Wisconsin and Michigan in a coordinated manner such that electric energy from one state was transmitted to the other, and vice versa, ''in appreciable amounts by the power company and by it commingled with energy generated in the two respective districts and then delivered to the [wholesale] customers * * *.''[52] The court also rejected the notion that the energy changed its form or character when it was stepped down in voltage before it reached the wholesale purchasers.[53]

The court in *Wisconsin-Michigan* distinguished between transmission and local distribution by focusing on wholesale sales of electric energy versus retail sales (''local rates'') of electric energy. It cited the House Report on the FPA, and characterized the legislative history as follows:

The legislative history, (H.R. Rep. No. 1318), 74th Cong., 1st Sess. pages 7, 8 and 27 (1935), discloses that the Congressional Committee intended that *the provisions of the (FPA) should apply to the transmission of electric energy in interstate commerce, i.e., the sale of energy at wholesale in interstate commerce, but not to the retail sale of any such energy in local distribution;* that the (FPA) left to the state the authority to fix local rates where the energy is brought in from other states, and that the rate making power of the (FPC) was to be confined to those *wholesale transmissions* which the Supreme Court had held in (*Attleboro*) to be beyond the reach of the state. Under that decision, said the committee, the rates charged in interstate wholesale transactions could not be regulated by the states. It defined a wholesale transaction as the sale of electric energy for resale.[54]

The Seventh Circuit's characterization of the House Report seems to equate transmission of electric energy in interstate commerce with the sale of energy at wholesale in interstate commerce. However, this interpretation is at odds with both the

[35] *CL&P*, 324 U.S. at 517.

[36] *Id.* at 518.

[37] *Id.* at 521.

[38] *Id.* at 522.

[39] *Id.* at 519–21.

[40] *Id.*

[41] *Id.* at 522, *quoting* Connecticut Light & Power Co. v. FPC, 141 F.2d 14, 18 (D.C. Cir. 1944).

[42] 324 U.S. at 529.

[43] *Id.* at 529–31.

[44] Id. at 531.

[45] It appears that while the Company received power (at one location) at 66 kV, it primarily owned facilities at 13.8 kV and below.

[46] 324 U.S. at 531.

[47] *Id.* at 531 (emphasis added).

[48] *Id.* at 534.

[49] *See* United States v. Public Utilities Commission of California, 345 U.S. 295, 316 (1953) (*Public Utilities Commission*): Certainly the concrete fact of resale of some portion of the electricity transmitted from a state to a point outside thereof invokes federal jurisdiction at the outset, despite the fact that the power thus used traveled along its interstate route ''commingled'' with other power sold by the same seller and eventually directly consumed by the same purchaser-distributor.

See also Arkansas Power & Light Co. v. FPC, 368 F.2d 376, 383 (8th Cir. 1966) (''Where a company is in fact a public utility, all wholesale sales for resale in interstate commerce are subject to the provisions of sections 205 and 206 of the (FPA), regardless of the facilities used.''). The Eighth Circuit further noted that the section 201(b) exemption applies to a company's status as a public utility and not to the Commission's jurisdiction over sales in interstate commerce for resale. *Id.*, citing *Public Utilities Commission, Colton, infra,* and *Wisconsin-Michigan, infra.*

[50] *Id.* at 536.

[51] 197 F.2d 472 (7th Cir. 1952), *cert. denied,* 345 U.S. 934 (1953) (*Wisconsin-Michigan*).

[52] *Id.* at 474.

[53] *Id.* (''Obviously the energy thus transmitted in interstate commerce is not changed in form or in character except that the voltage is reduced to an extent consistent with efficient economic management and operation.'').

[54] 197 F.2d at 476 (emphasis added).

plain words of the statute as well as the language of the House Report, both of which refer to transmission in interstate commerce separately from sales for resale in interstate commerce.[55] In addition, the Senate Report, which the Seventh Circuit did not mention, clearly recognized jurisdiction over all interstate transmission lines, whether or not a sale of energy is carried by those lines.[56]

The *Wisconsin-Michigan* court also cited analogous natural gas cases, stating that ''[t]he question is essentially, when does interstate commerce transportation end and where do the local distribution facilities first become operative.'' [57] The court further stated that:

(U)pon delivery to (the wholesaler) local distribution begins when he resells. His sales and distribution at retail are clearly local in character, and constitute only local distribution; but at no point before delivery to him has been completed, has interstate transmission terminated. In other words, ''facilities used in local distribution'' means facilities used for making resale and distribution to consumers, jurisdiction over which is left to the states. It was only because of this conclusion that the Supreme Court said, (citation omitted), the Act ''cut(s) sharply and cleanly between sales for resale and direct sales for consumptive uses.'' We think there is no ground for the position that local distribution includes any transmission occurring before the wholesaler who resells at retail is reached.[58]

The Seventh Circuit concluded that the sales for resale were made in interstate commerce; that local distribution had not begun; that the interstate character of the transmission persisted until delivery to the wholesaler; that, up to that point, no local distribution facilities were in operation and that, therefore, the sales were subject to Commission regulation.

In *Federal Power Commission v. Southern California Edison Company* (the *Colton* case),[59] the Supreme Court held that the FPA provides a clear line of demarcation between jurisdictional transactions and non-jurisdictional transactions. However, this case, too, involved bundled sales of electric energy. In the facts of the case, Southern California Edison Company (Edison) admitted that it was a public utility by virtue of owning two interstate transmission lines.[60] At issue was whether its sales of electric energy to the City of Colton, California, for resale to Colton's retail customers, were jurisdictional. Included in the electric energy that Edison sold to Colton was out-of-state electric energy from Hoover Dam.[61] The Commission ruled that the sale to Colton was a sale of electric energy at wholesale in interstate commerce subject to regulation under the FPA.[62] In upholding the Commission, the Court held that Edison's importation of out-of-state electricity for resale to Colton sufficed to confer federal jurisdiction.

The Court, citing an earlier Supreme Court case,[63] characterized Congressional intent in the FPA:

(W)hat Congress did was to adopt the test developed in the *Attleboro* line which denied state power to regulate a sale ''at wholesale to local distributing companies'' and allowed state regulation of a sale at ''local retail rates to ultimate consumers.'' [64]

The Court rejected the argument that FPC jurisdiction was confined to those interstate wholesale sales constitutionally beyond the power of state regulation by force of the Commerce Clause, and was to be determined on a case-by-case analysis of the impact of state regulation upon the national interest. The Court stated that in the FPA:

(C)ongress meant to draw a bright-line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis. This was done in the Power Act by making FPC jurisdiction plenary and extend[ed] it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.[65]

The Court held that ''(t)here is no such exception covering the Edison-Colton sale.'' [66]

Parties in the Colton case had raised the question of whether jurisdiction over the Colton sale was prevented by the ''local distribution'' proviso of section 201(b). The Court stated that whether facilities are local distribution facilities is a matter for the Commission to decide in the first instance. Citing *CL&P, supra,* it stated:

Whether facilities are used in local distribution—although a limitation on FPC jurisdiction and a legal standard that must be given effect in addition to the technological transmission test * * *—involves a question of fact to be decided by the FPC as an original matter.[67]

The Court cited evidentiary support and the Commission's expertise in such matters in upholding the Commission's determination that certain facilities owned by Edison were used exclusively to effect the wholesale sale to Colton and not for local distribution. Such facilities included 12 kV lines that served an industrial customer, several lighted highway signs, a residence and a railroad section house before they reached the transformers in the Colton substation. The FPC had held that those uses prior to the lines reaching the Colton substation did not transform the lines into local distribution facilities.[68]

In *Duke Power Company* v. *Federal Power Commission* (*Duke*),[69] the D.C. Circuit held that a public utility's acquisition of facilities used solely in local distribution, and which would continue to be used for local distribution, was beyond the Commission's jurisdiction under section 203. The case involved Duke Power Company's (Duke's) proposed acquisition of facilities owned by Clemson University (Clemson), which were used to distribute electricity off-campus to customers (primarily university personnel) in two South Carolina counties. Clemson purchased the power at wholesale from Duke. No one appeared to contest the conclusion that the 7 miles of distribution line and 418 service connections owned by Clemson were ''local distribution'' facilities.[70] Rather, the case turned on interpreting section 203 and whether it was intended to affect *only* acquisitions of jurisdictional facilities, or also to affect acquisitions of non-jurisdictional facilities. In interpreting section 203, however, the D.C. Circuit extensively analyzed and discussed the fundamental jurisdictional lines that Congress drew in section 201.

Citing to the *CL&P* case, the court in *Duke* stated:

The Act, as we have seen, effectuated federal control over the transmission and the sale at wholesale of electric energy in interstate commerce, and established the Commission's regulatory power over public utilities engaging in *either* of these pursuits.[71]

However, quoting *CL&P*, the court further stated:

The expression ''facilities used in local distribution'' is one of relative generality. But as used in this Act it is not a meaningless generality in the light of our history and the structure of our government. We hold the phrase to be a limitation on jurisdiction and a legal standard that must be given effect in this case in addition to the technological transmission test.[72]

The court further rejected the Commission's concept that, in order to determine whether jurisdiction over any particular acquisition existed, the impact of local supervision be measured on a case-by-case basis. Quoting from *Colton*, the court stated:

[T]his ''flexible approach''—involving as it does the consideration, *inter alia*, of ''the

[55] *See* H.R. Rep. No. 1318 at 27. (''Subsection (b) confers jurisdiction upon the Commission over the transmission of electric energy in interstate commerce *and* the sale of electric energy in wholesale in interstate commerce * * *.'' emphasis added).

[56] *See* S. Rep. No. 621 at 48 (''Jurisdiction is asserted over all interstate transmission lines whether or not there is a sale of the energy carried by those lines * * *.'').

[57] 197 F.2d at 477.

[58] *Id.*, citing FPC v. East Ohio Gas Co., 338 U.S. 464 (1950) (*East Ohio*).

[59] 376 U.S. 205 (1964) (*Colton*).

[60] The Supreme Court noted that Edison's status as a public utility did not decide the question of whether the FPC could assert jurisdiction over the rates for the Edison-Colton sale. *Id.* at 208 n.3.

[61] *Id.* at 208, 209 & n.5.

[62] *Id.* at 208. *See* Arkansas Electric Cooperative Corp. v. Arkansas Public Service Commission, 461 U.S. 375, 380 (1983) (''(*Colton*) held, among other things, that * * * a California utility that received some of its power from out-of-state was subject to federal and not state regulation in its sales of electricity to a California municipality that resold the bulk of the power to others.'').

[63] Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 504 (1942).

[64] 376 U.S. at 214.

[65] *Id.* at 215–216.

[66] *Id.* at 216 (footnote omitted).

[67] *Id.* at 210 n.6 (citation omitted).

[68] *Id.* at 210 n.6.

[69] 401 F.2d 930 (D.C. Cir. 1968) (*Duke*).

[70] Duke delivered power to Clemson at a distribution voltage of 4,160 volts. The step-down transformers by which the voltage was reduced, and the substations at which the delivery was effected, were owned by Duke. 401 F.2d at 931, n.8.

[71] 401 F.2d at 938–39 (emphasis added, footnotes omitted).

[72] *Id.* (footnote omitted).

effect of the regulation upon the national interest in the commerce''—has been flatly rejected as a technique for resolving jurisdictional conflicts between the Commission and state bodies. * * * We think that like the line ''(i)t cut sharply and cleanly between sales for resale and direct sales for consumptive uses'' to facilitate jurisdictional determinations in rate regulation, ''Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis,'' in distributing regulatory power over the acquisition of facilities.[73]

The court rejected the Commission's argument that jurisdiction over the merger or consolidation of jurisdictional facilities with those of any other ''person'' under section 203 gave the Commission jurisdiction over Duke's acquisition. The court stated that the FPA reflects a policy '''that matters largely of a local nature, even though interstate in character, should be handled locally and should receive the consideration of local [officials] familiar with the local conditions in the communities involved.'''[74]

Federal Power Commission v. *Florida Power & Light Company*[75] is the last major court case to address the Commission's transmission jurisdiction. In this case, the Commission sought to impose its accounting rules upon Florida Power & Light Company (Florida Power & Light). The company's system lay solely within the borders of Florida and did not directly connect with any out-of-state utility.[76] The Commission held that Florida Power & Light did own facilities that transmitted electric energy in interstate commerce, but the Court of Appeals for the Fifth Circuit ruled that the Commission did not have substantial evidence to support its finding.

The Supreme Court reversed. The Supreme Court noted that Florida Power & Light was a member of the Florida Power Pool along with Florida Power Corporation (Florida Power Corp.).[77] In turn, Florida Power Corp. connected with Georgia Power Company (Georgia Power) at a ''bus''[78] south of the Georgia-Florida border.[79] Florida Power Corp. regularly exchanged power with Georgia Power.[80] In many instances, Florida Power Corp. transferred power to Florida Power & Light instantly after receiving power from Georgia Power, and transferred power to Georgia Power immediately after receiving power from Florida Power & Light.[81] The Supreme Court found that power commingled in the bus moved across state lines, and concluded that Florida Power & Light engaged in transmission in interstate commerce. The Court held that, to establish jurisdiction, the Commission need only show that ''some (Florida Power & Light) power goes out of State.''[82] The Court further explained that ''(i)f any (Florida Power & Light) power has reached Georgia, *or* (if Florida Power & Light) makes use of any Georgia power * * * FPC jurisdiction will attach * * *.''[83]

There is also a line of cases that address, among other things, what constitutes a Commission jurisdictional ''sale of electric energy at wholesale''[84] under section 201 of the FPA.[85] These cases all concerned bundled sales. While the issues posed above involve unbundled wheeling, the ''resale'' cases are helpful to the extent they suggest that local distribution takes place only *after* power is subdivided. *See, e.g.,* 345 U.S. at 316 (''the facilities supplied 'local distribution' only after the current was subdivided for individual consumers.'').

4. Natural Gas Act

The Natural Gas Act (NGA) was adopted in 1938. Like the FPA, the NGA contains language limiting the Commission's jurisdiction in situations involving local distribution.[86]

Section 1(b) of the NGA provides:

The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural gas companies engaged in such transportation or sale, *but shall not apply* to any other transportation or sale of natural gas or *to the local distribution of natural gas or to the facilities used for such distribution* or to the production or gathering of natural.[87]

There is similarity in many respects between the House and Senate Reports on the FPA and the NGA with respect to the jurisdiction given the Commission. For example, all four reports mention *Attleboro* as placing interstate wholesale transactions beyond the reach of the States. As indicated in the House Report on the NGA, the States could ''regulate sales to consumers even though such sales are in interstate commerce, such sales being considered local in character and in the absence of congressional prohibition subject to State regulation.'' (*See* H.R. Rep. No. 709, 75th Cong., 1st Sess. 1). However, the House and Senate Reports on the NGA contain identical language not found in the reports on the FPA:

In view of the importance of section 1(b), which states the scope of the act, it seems advisable to comment on certain provisions appearing therein. It will be noted that this subsection of the bill, after affirmatively stating the matters to which the act is to apply, contains a provision specifying what the act is not to apply to, as follows:

But shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

The quoted words are not actually necessary, as the matters specified therein could not be said fairly to be covered by the language affirmatively stating the jurisdiction of the Commission, but similar language was in previous bills, and, rather than invite the contention, however unfounded, that the elimination of the negative language would broaden the scope of the act, the committee has included it in this bill. *That part of the negative declaration stating that the act shall not apply to ''the local distribution of natural gas'' is surplusage by reason of the fact that distribution is made only to consumers in connection with sales, and since no jurisdiction is given to the Commission to regulate sales to consumers the Commission would have no authority over distribution, whether or not local in character.* (Emphasis added).[88]

As a result of this language it can be argued that Congress considered distribution (and local distribution) only in the context of bundled retail sales of natural gas. In fact, it appears that all of the court cases affirming the states' right to regulate local distribution of gas have involved bundled retail sales. *See Panhandle Eastern Pipe Line Co.* v. *Michigan Public Service Commission,* 341 U.S. 329 (1951) (*Panhandle*). There the Court, in affirming the State of Michigan's right to regulate an interstate pipeline's proposed bundled retail sales of gas to industrial consumers, noted that the pipeline company proposed to lay pipeline in ''the streets and alleys of Detroit'' and ignored the local distribution company's request for additional gas to meet the increased needs of the industrial consumers. *Id.* at 333. While the Court based its holding on a state's authority to regulate direct (retail) sales to an end-user, rather than on the basis of the section 1(b) local distribution provision, it also found that the proposed sales were ''primarily of local interest'' and ''emphasized the need for local regulation.'' *Id.* Two years before *Panhandle,* the Supreme Court issued its decision in *FPC* v. *East Ohio Gas Co.,* 338 U.S. 465 (1949) (*East Ohio*). East Ohio Gas Company owned and operated a natural gas business wholly within the State of Ohio. The company sold gas only to Ohio customers but most of the gas was transported to Ohio from other states by interstate pipelines. These interstate pipelines connected inside Ohio with East Ohio's large high pressure lines. The gas then was transported over 100 miles through East Ohio's system to its local distribution system. East Ohio argued that it was exempt from Commission jurisdiction because all of its facilities were local distribution.

The Court disagreed, finding the Commission's jurisdiction extends over the

[73] *Id.* at 949 (footnotes omitted).

[74] *Id.* at 936 (quoting from Hearings on H.R. 5423 before the House Committee on Interstate and Foreign Commerce, 74th Cong., 1st Sess. 393 (1935) (testimony of then-FPC Commissioner Seavey)).

[75] 404 U.S. 453, *reh'g denied,* 405 U.S. 948 (1972) (*Florida Power & Light*).

[76] 404 U.S. at 456.

[77] *Id.* at 456.

[78] A ''bus'' is a connector or group of connectors that serves as a common connection for two or more circuits.

[79] 404 U.S. at 457.

[80] *Id.*

[81] *Id.* at 457 & n.8.

[82] *Id.* at 461. (emphasis omitted).

[83] *Id.* at 461 n.10. (emphasis added).

[84] *See* Section 201(d), 16 U.S.C. 824(d) (1988).

[85] *Public Utilities Commission, supra* note 345; City of Oakland, California v. FERC, 754 F.2d 1378 (9th Cir. 1985) (*Oakland*). See also Alexander v. FERC, 609 F.2d 543 (D.C. Cir. 1979) (*Alexander*).

[86] Courts often rely on cases construing the NGA when interpreting the FPA, and vice versa. *E.g.,* Arkansas Louisiana Gas Co. v. Hall, 453 U.S. 571, 577 n.7 (1981).

[87] 15 U.S.C. 717(b) (emphasis added).

[88] H.R. Rep. No. 709, 75th Cong., 1st Sess. 3 (1937); S. Rep. No. 1162, 75th Cong., 1st Sess. 3 (1937).

transportation of gas in interstate commerce through high-pressure transmission lines and that distribution did not begin until the point where pressure is reduced and gas enters local mains. The Court stated that: ''[w]hat Congress must have meant by 'facilities' for 'local distribution' was equipment for distributing gas among customers within a particular local community, not the high-pressure pipelines transporting the gas to the local mains.'' [89]

The Commission relied in part on *East Ohio's* high pressure/low pressure distinction in a recent NGA section 7 certificate case which authorized construction of facilities to bypass the local distribution company.[90] On appeal, the California Commission argued that under section 1(b) it should at least have ''jurisdiction over the 'taps, meters and other tie-in facilities' that link the pipeline to end users.'' [91] The court disagreed:

While as a matter of ordinary English 'local distribution' might be understood to encompass any delivery to an end user, that is hardly the only or even more plausible reading. Distribution conjures up receiving a large quantity of some good and parcelling it out among many takers.[92]

After reviewing the report language discussed above, the court also stated:

Insofar as congressional committees spoke to the matter * * * they appear to have viewed distribution as confined to its parcelling out function and (probably) even more narrowly, to parcelling out *accompanied by* retail sales. [93]

In *Cascade Natural Gas Corporation* v. *FERC, et al.* (*Cascade*), the court affirmed the Commission's authorizing an interstate pipeline under section 7 of the NGA ''to construct a tap and meter facility that would allow it to deliver natural gas directly to two industrial consumers * * *.''[94] To reach the interstate pipeline, the industrials constructed a nine-mile pipeline. Together, the facilities bypassed the local distribution company.[95]

The court rejected arguments that section 1(b) deprived the Commission of jurisdiction holding that:

''Local distribution,'' as Congress viewed the term, involves two components: the retail sale of natural gas and its local delivery, normally through a network of branch lines designed to supply local consumers.[96]

5. Analysis

a. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

The case law supports the conclusion that any facilities of a public utility used to deliver electric energy in interstate commerce to a wholesale purchaser, whether such facilities are labeled ''transmission,'' ''distribution'' or ''local distribution,'' are subject to the Commission's jurisdiction under sections 205 and 206.

This conclusion is supported by *Public Utilities Commission, supra,* in which the Supreme Court, in the section of its opinion addressing the section 201(b) local distribution provision, held that local distribution facilities began ''only after the current was subdivided for individual consumers.'' [97] *Wisconsin-Michigan, supra,* in which the Seventh Circuit held that there is no local distribution until the wholesaler who re-sells at retail is reached, is to like effect.

This conclusion, which results in a ''functional'' line being drawn to determine Commission jurisdiction, is not only consistent with the case law under section 201, but is also consistent with our interpretation of the line drawn under newly amended FPA sections 211 and 212. As long as electric energy is being sold to a legitimate wholesale purchaser, we believe the Commission has jurisdiction under sections 201, 205, and 206 of the FPA over the public utility's facilities used to deliver electric energy to that purchaser.

b. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier directly to an end user?

In analyzing jurisdiction over unbundled retail wheeling, we believe it is important to distinguish between unbundled wheeling provided by the public utility who previously provided bundled retail service to the end user, and unbundled wheeling provided by other public utilities to the end user. For example, a former bundled retail customer may need unbundled wheeling services from its previous public utility generation supplier, as well as unbundled wheeling from one or more intervening public utilities, in order to reach a distant generation supplier. In this scenario, the Commission believes it would have jurisdiction over all of the facilities used for the unbundled wheeling provided by the intervening public utilities.[98] The more difficult issue is whether some portion of the facilities used to transmit energy from the transmitting utility in closest proximity to the end user (the former supplier of the bundled product) is local distribution facilities. We believe that in most, if not all circumstances, some portion will be local distribution facilities.

The case law is replete with statements that the local distribution provision of section 201 must be given effect. However, the Supreme Court in both *CL&P* and *Colton, supra,* has stated that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. Thus, there is no clear case law on a ''bright line'' between transmission and local distribution. In addition, regardless of the details of the chain of delivery services necessary to move electric energy from the generator to the end user, in most cases the last public utility in the chain will use facilities that historically were considered local distribution facilities. Accordingly, unlike the situation involving unbundled wholesale wheeling, for which the case law clearly supports a ''functional'' test, the Commission believes the case law and practical realities of a changing industry support an analysis of local distribution facilities based on the facilities' functional as well as technical characteristics.

While it would be preferable to draw an absolutely ''bright'' line (*e.g.*, based on technical characteristics such as voltage), the Commission does not believe this is required by the case law and, importantly, would not be a workable approach in all cases because of the variety of circumstances that may arise and because utilities themselves classify facilities differently (*e.g.*, one utility may classify a 69 kV facility as transmission; another may classify it as distribution).

Therefore, the Commission is adopting several indicators it will evaluate in determining whether particular facilities are transmission or local distribution in the case of vertically integrated transmission and distribution utilities: [99]

- Local distribution facilities are normally in close proximity to retail customers.
- Local distribution facilities are primarily radial in character.
- Power flows into local distribution systems, it rarely, if ever, flows out.
- When power enters a local distribution system, it is not reconsigned or transported on to some other market.
- Power entering a local distribution system is consumed in a comparatively restricted geographical area.
- Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
- Local distribution systems will be of reduced voltage.[100]

In summary, for unbundled wholesale wheeling the Commission will apply a

[89] 338 U.S. at 469–70.

[90] *See* Mojave Pipeline Company, 35 FERC ¶ 61,199 (1986), *reh'g denied,* 41 FERC ¶ 61,040 (1987), *reh'g denied,* 42 FERC ¶ 61,351 (1988); *see also* Mojave Pipeline Company, 66 FERC ¶ 61,194 (1994), *reh'g pending.*

[91] *See* Public Utilities Commission of the State of California v. FERC, *et al.,* 900 F.2d 269, 273 (D.C. Cir. 1990) (footnote omitted) (*WyCal*).

[92] *Id.* at 276.

[93] *Id.* (emphasis in original).

[94] 955 F.2d 1412, 1414 (10th Cir. 1992).

[95] Unlike the situation in *WyCal* where the pipeline made direct sales to end users, in *Cascade* the pipeline transported gas purchased from third parties. *See* Northwest Pipeline Corporation, 51 FERC ¶ 61,289 at 61,909 (1990).

[96] *Cascade,* 955 F.2d at 1421.

[97] 345 U.S. at 316 (footnote omitted).

[98] The Commission would not have jurisdiction over the rates for the sale of generation by the distant supplier because the transaction would be a retail sale of electric energy.

[99] In the case of a distribution-only utility, which is franchised by a State or local government and sells only at retail, all of the circuits (and related wires, transformers, towers, and rights of way) which it owns or operates (regardless of voltage) would be local distribution facilities.

[100] The Commission has analyzed utilities' filings required by the Commission's regulations. These filings are made on FERC Form No. 1. While there is no uniform breakpoint between transmission and distribution, it appears that utilities account for facilities operated at greater than 30 kV as transmission and that distribution facilities are usually less than 40 kV.

functional test. The only definitive question will be whether the entity to whom the power is delivered is a lawful wholesaler. For unbundled retail wheeling the Commission will apply a combination functional-technical test that will take into account technical characteristics of the facilities used for the wheeling. The Commission concludes that these tests are consistent with the FPA, its legislative history and the case law discussed above.

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APPENDIX H
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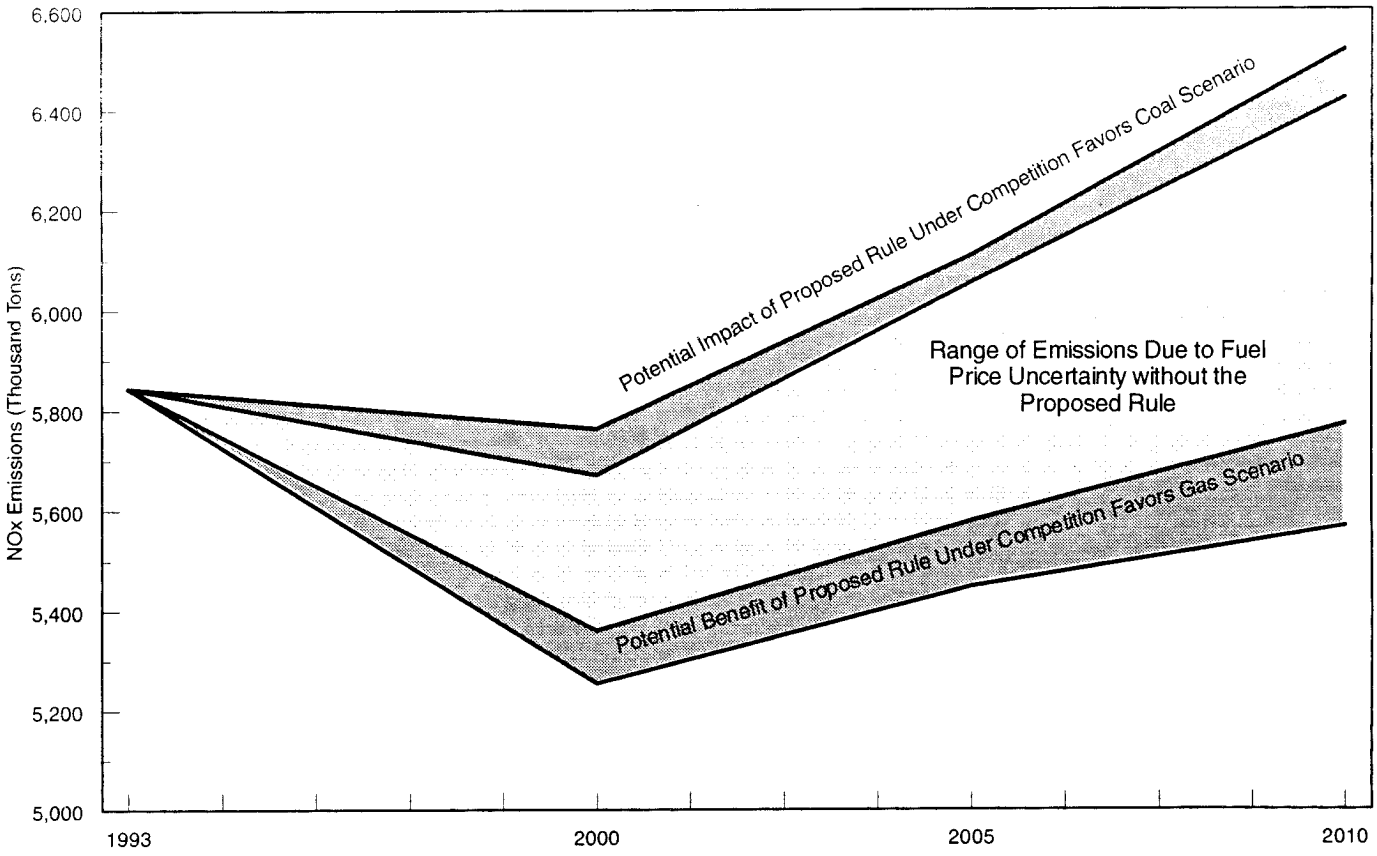
Figure ES-1. Total U.S. NOx Emissions



Source for 1993 data: Energy Information Administration, *Electric Power Annual*.
Note: All estimates include NOx emissions adjustments for MOU in the Ozone Transport Region.

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APPENDIX H.—TABLE ES–2.—NATIONAL EMISSIONS OF NO_X *as Projected in Both Base Cases and All Proposed Rule Scenarios*
[Thousand tons]

Year	Under assumption that relative gas and coal prices remain constant		Under assumption that gas prices increase compared to coal prices		
	Constant price-differential base case	Competition-favors-gas proposed rule scenario	High-price-differential base case	Competition-favors-coal proposed rule scenario	Low response proposed rule scenario
1993	5,844	5,844	5,844	5,844	5,844
2000	5,362	5,255	5,672	5,763	5,743
2005	5,579	5,449	6,053	6,108	6,056
2010	5,772	5,638	6,426	6,519	6,426

Promoting Wholesale Competition Through Open Access Non- Discriminatory Transmission Services by Public Utilities

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

(As corrected April 25, 1996)

[Docket No. RM95–8–000; Docket No. RM94–7–001]

Issued April 24, 1996.

HOECKER, Commissioner, *concurring in part and dissenting in part:*

General Observations

A. Four years and untold numbers of conferences, studies, and speculations after the Energy Policy Act, the Commission today takes a major step in bringing competition to the wholesale bulk power market in the United States. Order No. 888 (FERC Stats. & Regs. ¶ 31,036), together with our order establishing an open access same-time information system (OASIS) (Order No. 889, FERC Stats. & Regs. ¶ 31,037) and our proposal to conform all transmission tariffs to a uniform capacity reservation system (FERC Stats. & Regs. ¶ 32,517), will set in motion a dynamism seldom witnessed in the electric power business. In that sense, the organizational, operational, and economic consequences of the requirements we adopt today defy prediction. I believe nevertheless that the Commission's Final Rule today is a sound and reasoned decision about the industry as we now know it and as we think it may evolve. I therefore announce my unequivocal support for the order's basic tenets as we have chosen to implement them—the unbundled wholesale utility services, open and non-discriminatory access to transmission and to information about transmission, service comparability, an opportunity for increased competition among generation sources, coordination with and deference to state regulatory interests, and full recovery of eligible stranded investments.

B. Restructuring the electric power industry is a matter of national interest and priority. Electricity is ubiquitous. Its benefits are key to the American quality of life. Operating 750,000 MW of generation capacity arrayed across three synchronous regional transmission grids, the electric industry is the nation's most capital intensive. The 179 largest investor-owned utilities alone control nearly $600 billion in assets. And, total electricity revenues constitute between 3 and 4 percent of the gross domestic product (GDP)—larger than telecommunications, natural gas pipeline, and airline revenues combined.

Both the Congress and the President have recognized our obligation to ensure that these resources are used wisely and efficiently. We all recognize that systemic change is happening within the industry and that regulation must change to take maximum advantage of the most constructive of those forces. ''At the center of the success of our economy is the market, and at the core of the success of the market is competition,'' states the President in his 1996 *Economic Report* to the Congress; ''it is competition that drives down costs and prices, induces firms to produce the goods consumers want, and spurs innovation and the expansion of new markets abroad.'' Yet, as state and local governments consider the future of industries heretofore heavily regulated in the public interest, deregulation is not enough, states the President. Competition must be actively promoted and preserved from the abuses and distortions associated with monopoly power, as well as from outdated forms of regulation that provide inappropriate incentives.

In the electric utility restructuring process, several difficult challenges must still be met here and elsewhere. First, policymakers must make the tough choices to attack access discrimination and promote competition while also ensuring reliability and economical service. Success in these undertakings may require pricing innovation and structural reforms to attain significant long-run gains in efficiency and productivity. *Economic Report,* at 183–185. Second, no transition to a new regime of operating rules and assumptions, can be achieved reasonably if regulated companies are shorn of the opportunity to recover prudently incurred costs. Utility investments that may become stranded or uneconomic as competitive choice displaces franchise monopoly are estimated to represent a $100 billion-plus risk for public utilities. State and federal regulators must confront this issue in the interest of equity and a swift readjustment to the new competitive realities. As the President's *Economic Report* makes clear, it will be important to future suppliers of private capital for public use that a regulatory bargain made must remain a bargain kept. ''Credible government is key to a successful market economy, because it is so important for encouraging long-term investments.'' *Id.,* at 186–188. Third, maintaining competitive parity and environmental protection are key challenges as well. That means, among other things, that environmental policy must respond to the environmental risks associated with restructuring and vice versa. *Id.,* at 188–189. This assessment of the realities and challenges facing this Commission, its state counterparts, and the diverse elements of the industry substantially ratifies the Commission's actions today.

C. The long-run prospect for reform of the wholesale market is promising, though the task seems daunting. The preamble to the Final Rule begins by outlining the difficult issues that await this Commission and the industry: (1) Corporate organizational matters, including the role of independent system operators (ISOs) in promoting more efficient operation of the transmission system on a regional basis; (2) the need for a new merger policy, which I believe must be predicated on a thorough understanding of emerging markets and genuine ratepayer protections instead of a subjective tally of supposed ''benefits''; and (3) further efforts to make greater use of flow-based pricing where appropriate. In adopting the OASIS requirements, we have taken a first step in recognizing that competitive markets do not consist of wires and turbines alone, but of information also. Full competition requires the consolidation of the electron transportation system with the electronic information superhighway.

One thing is abundantly clear: restructuring will require continued innovation and fortitude from our capable staff, cooperation from state regulators, patience and foresight from legislators and, most of all, creativity, responsiveness, and endurance from both utility management and electric consumers.

II. Concurrence on Specific Issues

The Final Rule resolves certain matters of policy and law in ways which, despite my fundamental agreement, I would like to offer some additional perspectives.

A. Coordinating State and Federal Regulatory Interests

Perhaps no single issue will influence the success or failure of restructuring as will the capacity of the FERC and state regulators to reach meaningful accommodations as the electric utility industry becomes increasingly subject to competitive forces. The vertical organization and technological integration of the electric power business contributes to the impression of a regulatory system riddled with gaps and overlaps, interregional inequities, and uncertainty. To the extent that impression predominates in the months to come, the pressure from legislators and the financial community to devise single-minded national solutions to issues of regional or local significance will likely prove irresistible.

The regulation of this industry is a unique exercise in federalism. The Deputy Secretary of Energy wisely acknowledged months ago that, ''the aftermath of FERC's open access rulemaking will put to the test our ability to evolve improved means for unsnarling the governance problems of federal and state authorities.'' Charles B. Curtis, Remarks Before the Third DOE/NARUC National Symposium, December 4, 1995. I find no shortage of good ideas on how to achieve better state, federal, and inter-regional cooperation. But, unanswered questions persist about the availability of sufficient political will and leadership to achieve electricity markets that at once satisfy the need for operational efficiency on a regional level and also provide the ''opportunity for experimentation and market testing with the flexibility to comprehend local differences * * * [that is] the very genius of the federal system.'' *Id.*

Although it remains unclear today whether this challenge will be met, I firmly believe that the Final Rule is a sound resolution of the jurisdictional questions facing this Commission as a result of competition and open access. State PUC comments reflect enormous concern about the potential loss of jurisdiction over some wires and services, if and when ''retail transmission'' becomes unbundled. States raise legal objections to our claim of jurisdiction. While reaffirming our view that the Commission has exclusive jurisdiction over the rate, terms, and conditions of interstate transmission, today's order addresses state concerns squarely—first, by adhering to the practical distinctions between transmission and distribution set forth in the NOPR and, second, by according deference [1] to states where appropriate when

[1] The Commission leaves unexplored the precise meaning of ''deference'' in these circumstances. At

Continued

retail transmission services become subject to a FERC tariff. These accommodations will smooth the transition to a seamless competitive market with full customer choice, if and when individual states initiate retail competition.

While the Final Rule, not unexpectedly, manifests this Commission's strong interest in preventing balkanization of the interstate power market, nothing adopted by the Commission today, including the interpretation of its authority over retail transmission when retail service is unbundled, is inconsistent with the traditional state roles in developing regulatory, social, and environmental requirements and programs suited to the circumstances of their localities. Section I of the Final Rule is emphatic about this.

I will conclude with two observations on matters I believe to be of particular sensitivity to the states. First, it appears to me that state regulators may impose distribution and other non-bypassable charges or other retail requirements on direct access services, even in those circumstances where no distribution facilities can be identified under the functional/technical test. The Final Rule ensures that result by acknowledging state authority over distribution-related services under the FPA.

Second, state authority is traditionally employed to ensure that power production conforms to local economic, environmental, and resource diversity policy preferences. A state may wish, for example, to ensure that a direct access industrial customer is no less obligated to purchase power consistent with the resource diversity or environmental requirements than is that customer's franchise distribution utility. To the extent that state requirements to own or purchase a certain amount of generation from, say, renewable sources are enshrined in utility supply portfolios, those states have direct influence on the economic and environmental consequences of energy consumption in that jurisdiction. Moreover, such requirements ought to be compatible with open access transmission. However, it will be important that state authority over resource procurement be exercised on a not unduly discriminatory basis. In other words, a PUC may not treat in-state and out-of-state suppliers differently. If access over the network is non-discriminatory in nature, the federal regulatory and constitutional interests are arguably satisfied.

B. Environmental Effects of Restructuring

1. Last July, we instructed our staff to prepare an Environmental Impact Statement (EIS) in conjunction with this rulemaking. The Final EIS (FEIS), issued on April 12, 1996, is an impressive and, with respect to the air impacts of electric restructuring, a pioneering work. It considers in detail: (1) The possible environmental consequences of adopting this Rule, including a number of additional analyses requested by commenters, (2) alternative methods of pursuing open access transmission service, (3) a range of environmental mitigation actions proposed by commenters, and (4) the Commission's legal and technical ability to undertake environmental mitigation. On the whole, I find staff's studies to be analytically sound and generally in conformance with my understanding of this agency's powers to engage in environmental mitigation. Moreover, its conclusions and recommendations are thoughtful and well-reasoned. I therefore believe that consideration of the FEIS as part of the Commission's actions today meets our National Environmental Policy Act of 1969 (NEPA) obligations [2] and the requirement of reasoned decisionmaking.

The FEIS highlights a very important public health and social welfare issue, not to mention a matter of great financial importance to certain utilities. To be specific, the FEIS examines potential air quality impacts in the event generation increases from certain coal-fired units. Open transmission access is expected by some to stimulate that additional generation and hence additional nitrogen oxide (NO_X) emissions and related ozone formation. From these projections, a substantive and not altogether constructive debate has ensued. As Section V of the Final Rule describes more fully, the Commission conducted additional studies to respond to comments on the draft EIS, using new recommended baselines for comparison. The results confirm that the air quality impacts of the rule are within reason.

The Commission has satisfied itself that the three most pressing questions have been addressed: (1) What increment of the NO_X emissions problem may be attributable to this Final Rule? (2) Will Final Rule-induced NO_X emission increases be so significant and their impacts sufficiently adverse to justify an alternative regulatory approach, such as ''no action'' on utility restructuring? (3) Short of no action, can the Commission undertake direct actions that mitigate any potential adverse effects? Based on the FEIS, I can find no justification in the cause, size, or certainty of near-term emissions increases for delaying or diluting the Open Access Rule and no clear basis for a FERC-sponsored emissions control regime, even on an interim basis.

2. Having discharged our NEPA obligations, I cannot pretend that this matter of public interest is no longer of any interest or concern to us. Clean air is a birthright. Air emissions are therefore an important concern. I would not relegate this issue to the periphery of our deliberations. If the EIS process accomplishes nothing else, it has familiarized the FERC with the difficulties of addressing the seemingly intractable problem of NO_X emissions. The problem engenders interregional economic and environmental conflicts that can be addressed only by a sophisticated balancing of interests and a selfless commitment to the greater good. EPA and several commenters on our Rule express frustration over the progress being made to reduce NO_X emissions. For this and other environmental issues, such as NO_X waivers, resort to the courts has become customary, and complex technological and economic disputes are the norm. *See e.g., Electric Power Alert,* April 24, 1996, at 29–30.

Regions of the country differ, often vehemently, about the source and effects of ozone-causing emissions and how best to curb the generation and transport of pollutants that create ozone. Utilities in some regions have made commitments and invested heavily to achieve ''attainment'' levels, while the blessings of geography and circumstance have imposed no such burden on others. We recognize in essence that reconciling these interests is a task the Congress has assigned to the EPA. Although the Clean Air Act authorizes EPA to develop a national program to enforce emissions reduction largely through state environmental regulatory efforts (the so-called State Implementation Plans (SIPs)), the statutory process is ponderous in practice. Moreover, even where gains are expected to be made in the form of reduced NO_X emissions (*e.g.,* under EPA's pending rulemaking to set NO_X emissions limitations for certain types of utility boilers), those gains might arguably be offset by future increases in the demand for electricity or, according to some parties, by the additional power generation some say will be encouraged by open access transmission.

The inability to guarantee future NO_X reductions for a variety of reasons that range well beyond this Rule presents formidable challenges. EPA places great faith in the ability of the Ozone Transport Assessment Group (OTAG), a voluntary multi-state organization established in part to set up NO_X emission mitigation mechanism, to address these complex issues and achieve a resolution. It nevertheless appears to me that, for the most part, consensus remains distant. The alternative appears to be an even more protracted EPA procedure.

With respect to the gravamen of this issue (i.e., the establishment of an emissions cap and credit trading system reminiscent of what Congress ordered for sulphur dioxide (SO_2)), this Commission has no real choice but to defer to agencies with jurisdiction by law and special expertise. The EPA has done an outstanding job implementing the market-based SO_2 allowance program. It is widely regarded as both creative and successful.

one extreme, it could mean courteous regard for another's views and, at the other, binding submission to another's judgment. I would, for example, accord state views on cost allocation considerable or presumptive, but not conclusive, weight.

[2] NEPA (42 U.S.C. 4321–4370), the Council on Environmental Quality's (CEQ) regulations promulgated thereunder (40 CFR parts 1500–1508 (1995)), and our own environmental regulations supplementing those of CEQ (18 CFR part 380 (1995)) together establish an important procedural mechanism that was designed, not to impose upon this Commission substantive duties to achieve particular results, but to infuse our decisional processes with a broad awareness of the environmental consequences of our actions. Under NEPA, the Commission must in any applicable instance consider and weigh its core objectives and responsibilities under the Federal Power Act and the impacts of its actions on all aspects of the human environment—economic and social as well as ecological. This exercise requires the Commission to ascertain the availability and consider the feasibility of alternative approaches with lesser impacts. In other words, the Commission's duty is to take a ''hard look'' at the environmental effects of its major actions. Robertson v. Methow Valley Citizens Council, *et al.,* 490 U.S. 332 (1988); Strycker's Bay Neighborhood Council, Inc. v. Karlen, *et al.,* 444 U.S. 223 (1980). The EIS process fulfills that requirement.

OTAG, regardless of any concerns about its processes, brings together a broad range of regional interests, thereby offering an unprecedented opportunity for achieving consensus resolution of this difficult problem.

3. In my view, it behooves this Commission to assist in any way it can, consistent with its expertise and authority, to find consensual solutions. I do not think that means denying polluting utilities access to the transmission system and thereby merely reinforcing their monopoly power. Rather, we must stand ready to assist EPA and OTAG in making competition and environmental responsibility equally attractive. We have begun providing that assistance by ensuring (see II.A. above) that state regulators retain their customary authority under state law to structure the generation and purchase power portfolios of state-regulated utilities. Moreover, the Commission has in the past addressed through its rate jurisdiction various public interest goals, including environmental concerns, intergenerational equities, and least-cost planning needs. For instance, in order to encourage capital investment in pollution control equipment and conservation, the Commission has long allowed utilities to include in rate base the costs of ''construction work in progress'' (CWIP) for pollution control devices and fuel conversion measures that discourage use of certain fossil fuels.[3] In addition, utilities are not eligible for CWIP treatment for plant construction not shown to be the product of integrated resource planning.[4]

With respect to the NO_X issue specifically, the Commission is competent to help facilitate an emissions cap and trading system. For instance, the accounting treatment provided for the cost of SO_2 emissions allowances in rates was done to assist implementation of the Clean Air Act.[5] The same accommodations could be instituted for a NO_X program. Perhaps the greatest potential for DOE–EPA–OTAG–FERC collaboration and consultation involves our knowledge of the industry and, after preparing the FEIS, our familiarity with the NO_X problem itself. That information should be useful beyond the confines of this rulemaking. In addition, the FEIS indicates (at p. 7–22) that we can structure the electronic bulletin board systems we require so as to facilitate the posting of emissions data required by EPA.

4. Based upon the mutual concerns and the different but complementary expertise of the affected agencies, I encourage the development of consultative mechanisms, memoranda of understanding, or other procedures that will support and help ensure the success of OTAG's efforts. Such efforts must be consistent with the goals and allocation of responsibilities under the Clean Air Act, and our own regulatory role. Restructuring may pose some environmental risks. We think they are small and (at least eventually) manageable. Further experience is likely to demonstrate that restructuring opens up new possibilities for addressing longstanding environmental problems associated with utility operations. Open access enhances the prospects for environmental dispatch on a statewide or regional basis. It gives isolated renewable plants, particularly hydroelectric and wind power units that are tied to specific geographical features, better market access. I must note that investments in DSM and renewable resources, which offer relatively stable costs, may be an attractive component of utilities' generation portfolios because they also minimize risks. And, as restructuring makes electricity a more customer-driven business, the public's documented preference for environmentally benign power will become more powerful. In addition, efficient markets provide the necessary means to ''marketize'' environmental rules and perhaps to modify siting and other regulatory processes that are predicated on the vertical integration of the utility sector. And, finally, energy services companies that can promote conservation and generation alternatives require more open and dynamic markets. For the environment, the prospects offered by restructuring are exciting. Inhibiting or stopping its development will not help it.

III. Partial Dissent

The Final Rule announces that the Commission will be the ''primary forum'' to hear stranded cost claims where a retail power customer turns wholesale wheeling customer, usually through a municipalization (Situation 2). Although the Final Rule recognizes that states *do* have authority to deal with stranded costs in Situation 2, the majority nevertheless instructs parties to bring their claims to this Commission ''in the first instance.'' However, where costs are stranded due to state authorized retail wheeling (Situation 3), the majority takes a different and, I contend, incongruent approach that effectively denies any forum for those costs if state regulators possess authority to act but do not do so. Because I find nothing in policy or law to commend this approach, I respectfully dissent.[6]

I take issue with the ''primary forum'' approach because I believe that it: (1) Requires the Commission to second-guess state determinations on recovery of costs incurred at retail at a time when many states are addressing the issue; (2) will encourage forum shopping; and (3) is inconsistent with our approach in the retail wheeling situation; and (4) involves an unnecessary legal risk for the Commission.

A. Second-Guessing State Determinations of Retail Stranded Costs is Unwise and Unnecessary

The Final Rule's stranded cost recovery methodologies and the underlying jurisdictional assumptions are aimed at achieving full recovery of all legitimate, verifiable and prudent stranded costs, consistent with a utility's reasonable expectations and the justness and reasonableness of the underlying contract. I believe that this is a worthy objective, but it is not one which requires the Commission to second-guess state determinations. As state proceedings now reveal, the Commission's leadership in raising this issue has borne fruit. Where municipalization is occurring, states are addressing stranded costs responsibly. In nearby Virginia, for example, the Virginia State Corporation Commission has interceded into the dispute between Virginia Electric Power Company and the City of Falls Church over the City's plans to undertake a ''muni-lite'' form of municipalization. Moreover, the record before us today does not endorse the view that municipalization constitutes a major bypass threat to stranded cost recovery.

Notwithstanding such developments, the Final Rule announces that the Commission will be the ''primary forum'' to hear stranded cost claims where a retail power customer turns wholesale wheeling customer, usually through a municipalization. While declaration of ''primary forum'' status sounds very legalistic, there is in fact no legal basis for it. The policy is not founded on a concept of federal preemption in the area. Indeed, the Federal Power Act provides no basis for preemption. Moreover, the Final Rule recognizes that states *do* have authority to deal with stranded costs in these circumstances. The majority's instruction to bring claims directly to FERC will, if anything, afford states a reason to avoid this difficult issue altogether.

B. The ''Primary Forum'' Approach May Encourage Forum Shopping

As a policy matter, the majority's approach is peculiar on its face. Although the ''primary forum'' approach is intended to eliminate forum shopping, it will not achieve even that objective. Indeed, I think the ''primary forum'' approach may encourage parties to forum shop. State commissions or legislatures will often provide for stranded cost recovery at the time the wholesale entity is formed. Similarly, condemnation proceedings may provide for stranded costs in whole or part. Moreover, standards for stranded cost recovery are occasionally prescribed by statute. In reality, the Commission cannot preclude the states from acting on stranded cost issues and our proposed rule may encourage rather than discourage forum shopping.

C. The ''Primary Forum'' Approach Covers Fact Situations Largely Indistinguishable From the Retail Wheeling Scenario

The majority's decision to take primary jurisdiction of costs where a retail power customer becomes wholesale wheeling customer through municipalization and to distance itself from virtually any cost recovery responsibility where retail power customers becomes retail wheeling customers does not withstand scrutiny. These are not factually distinguishable cases, insofar as jurisdiction over stranded costs is concerned. The inadequacy of the majority's reasoning is palpable because it has adopted very different policies with respect to two stranded cost situations that, if properly understood, are virtually indistinguishable.

[3] 18 CFR 35.25 (1995).

[4] 18 CFR 35.13(h)(38) (1995).

[5] Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990, Order No. 552, III FERC Statutes and Regulations ¶30,967 (1993).

[6] My views conform generally to Commissioner Massey's partial dissent today.

First, in both Situations 2 and 3, retail power costs are stranded by customers who gain access to FERC jurisdictional transmission tariffs via state action. In Situation 2, state municipalization law governs. In Situation 3, the state has authorized retail wheeling by statute or regulation, or both. Notwithstanding the need for state authorization in both cases, the majority decides that the Commission should be the ''primary forum'' in Situation 2, but that a much more narrow approach to retail stranded costs in Situation 3.[7] The more aggressive ''primary forum'' approach to municipalization is predicated on the view that any strandings are a result of an inducement (*i.e.*, market options) created by this Commission's Open Access Rule. Yet, since both wholesale transmission customers and retail transmission customers are ''eligible customers'' under the tariffs required by this Rule, if the Rule induces the stranding of retail power costs in one situation, it obviously does it in both.

As commenters have noted, the relationship between FERC-regulated transmission service and retail power customers is generally the same in both Situations 2 and 3.[8] The similarity runs first to the actions that actually cause costs to be stranded. While it is true that retail wheeling will only occur pursuant to state legislative or regulatory action, it is also true that a retail customer can only convert to wholesale status (*e.g.*, municipalize) pursuant to state law. This process sometimes may occur in the absence of regulatory or other oversight (*e.g.*, municipalization under pre-established statutory scheme), or with direct and immediate review and approval. The current evidence reflects active state commission oversight, typically. In this latter case, there is even less reason to distinguish between these Situations.

The majority implicitly seeks to delimit the area of appropriate state authority over stranded costs according to whether the state acts directly and by current enactments to authorize retail wheeling, on one hand, or less directly through established state municipalization laws, on the other. However, costs could be stranded under state law by either action. Under the former scenario, however, a state is presumed to be more willing and capable of dealing with stranded costs. Under the latter, it is presupposed to be less interested. This distinction is specious.

A second similarity pertains to the jurisdictional status of transmission service. The Commission has been clear and consistent that the FPA gives the Commission exclusive jurisdiction over interstate transmission service, regardless of whether the customer is a wholesale or a retail wheeling customer. It is this authority upon which we rely to claim jurisdiction over transmission assets and related costs originally incurred to provide customers at the retail level with bundled service. New wheeling customers in both Situations 2 and 3 will take service under FERC open access tariffs. There are identical cost-causational facts in Situations 2 and 3, yet the majority adopts very different outcomes in each case under the Final Rule.

D. The ''Primary Forum'' Approach is More Subject to Legal Challenge

In my view, our disagreement involves more than a policy choice. The majority's chosen approach clearly makes our stranded cost recovery approach more vulnerable to a legal challenge. The cost recovery scheme which would result from the majority's approach will render a FERC-ordered transmission surcharge to recover retail stranded costs susceptible to legal challenge on the basis that it is anti-competitive and unduly discriminatory. The ''primary forum'' approach imposes upon a retail-turned-wholesale customer something akin to double jeopardy. In other words, a departing customer might have to pay both an exit fee for the retail costs which the state commission finds it has stranded and, in addition, an entry fee for wholesale access in the amount of the additional retail stranded costs which FERC determines are inadequately covered by state proceedings.

This, in my view, makes the Final Rule more susceptible to challenges that FERC's transmission surcharge is anti-competitive. *E.g., Cajun Electric Power Cooperative, Inc.* v. *FERC,* 28 F.3d 173 (D.C. Cir. 1994). The second-guessing of states inherent in the ''primary forum'' approach makes any arguments that stranded cost recovery is anti-competitive more difficult to overcome than if the stranded costs resulted from wholesale customers simply changing wholesale suppliers. This is because, unlike wholesale-to-wholesale strandings, the Commission cannot plausibly argue that the costs incurred were originally addressed in the context of its own rate decisions or were previously part of its responsibility for administering wholesale service obligations.

I am strongly persuaded that the Commission would be on much stronger legal ground if we were to treat state authority over stranded costs with the same deference in the municipalization or ''retail-turned-wholesale'' situation in the same manner as the Final Rule prescribes for situations where retail wheeling occurs. In the latter case, the Commission ought to provide a forum where neither the state legislature nor the state commission attempts to address this important transition issue.

James J. Hoecker,

Commissioner.

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

[Docket No. RM95–8–000; Docket No. RM94–7–001]

Issued April 24, 1996.

MASSEY, Commissioner, *dissenting in part:*

I support all of the provisions of this rule save one, the provision on stranded costs arising from retail competition and from municipalization. When the Commission issued the Notice of Proposed Rulemaking, I stated that the Commission should treat stranded costs arising from retail competition and municipalizations similarly, as follows:

For either retail competition or municipalization, when the state commission has authority to address the issue, and uses such authority to decide the recoverability of the stranded costs, the state's decision should not be second-guessed by this Commission. However, when a state commission does not have the authority to decide the recoverability of stranded costs, or has authority but does not use it, this Commission should act on requests for stranded cost recovery.

My approach would assure utilities of getting a decision on the merits of their claim. Costs would not be stranded for lack of a regulatory decision. At the same time, this Commission would allow states to make decisions, when they have authority, on issues of critical concern to their local utilities and ratepayers. Only if states lack, or fail to use, such authority would this Commission step in to assure the utility of receiving a decision on the merits.

For the reasons I stated then, I still disagree with the rule's approach to stranded costs arising from retail competition or municipalization. In all other respects, I support this rule.

William L. Massey,

Commissioner.

[FR Doc. 96–10694 Filed 5–9–96; 8:45 am]

BILLING CODE 6717–01–P

[7] The policy adopted with respect to Situation 3 is that the Commission would only be a forum for hearing stranded costs issues in the narrow circumstance where ''the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required.'' The majority fails to address what would happen if a legislature addresses the issue of stranded costs directly without delegating the task to a state regulatory authority. I would hope that the Commission would not set itself up for confrontation with a state legislature and I would have preferred that to also exclude those circumstances ''where the state otherwise addresses the issue'' from the circumstances in which the Commission would act in Situation 3.

[8] This argument is made both by commenters arguing that the Commission has no jurisdiction over stranded costs in Situation 2 or 3 (California Public Utilities Commission Initial Comments at 7) and by commenters arguing that the Commission should assert primary jurisdiction over stranded costs in both Situations (*see e.g.*, Edison Electric Institute Initial Comments at IV–13; Coalition For Economic Competition Initial Comments at 22; Utilities For An Improved Transition Initial Comments at 16–26).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 37

[Docket No. RM95–9–000; Order No. 889]

Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct

April 24, 1996.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is adding rules establishing and governing an Open Access Same-time Information System (OASIS) (formerly real-time information networks) and prescribing standards of conduct. Under this final rule, each public utility (or its agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce will be required to create or participate in an OASIS that will provide open access transmission customers and potential open access transmission customers with information, provided by electronic means, about available transmission capacity, prices, and other information that will enable them to obtain open access non-discriminatory transmission service. This final rule requires each public utility subject to the rule to implement standards of conduct to functionally separate transmission and wholesale power merchant functions and the creation of a basic OASIS system. In addition, some of the standards and formats for OASIS nodes are prescribed in a document entitled *OASIS Standards and Communication Protocols* that is being issued with the final rule. The Commission also is establishing further procedures to complete the standards for displays and formats. The development of OASIS requirements will continue in a Phase II, in which the Commission will continue to develop the requirements for a fully functional OASIS.

Effective Date: This final rule will become effective on July 9, 1996.

Compliance Date: Compliance with the standards of conduct and operation of an OASIS meeting the requirements of this final rule must commence on or before November 1, 1996.

Conference Date: A technical conference on any remaining issues will be held on June 17, 1996.

ADDRESSES: The technical conference will be held at the Commission's headquarters at 888 First Street, NE., Washington, DC. 20426.

FOR FURTHER INFORMATION CONTACT:

Marvin Rosenberg (Technical Information), Office of Economic Policy, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 208–1283

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Gary D. Cohen (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 208–0321

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in the Public Reference Room at 888 First Street, NE., Washington, DC 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing 202–208–1397 if dialing locally or 1–800–856–3920 if dialing long distance. CIPS is also available through the Fed World system (by modem or Internet). To access CIPS, set your communications software to 19200, 14400, 12000, 9600, 7200, 4800, 2400, or 1200 bps, full duplex, no parity, 8 data bits and 1 stop bit. The full text of this order will be available on CIPS indefinitely in ASCII and Wordperfect 5.1 format. The complete text on diskette in WordPerfect format may also be purchased from the Commission's copy contractor, La Dorn Systems Corporation, also located in the Public Reference Room at 888 First Street, NE., Washington, DC 20426.

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I. Introduction

The Federal Energy Regulatory Commission (Commission) is promulgating new regulations amending 18 CFR to add Part 37 containing rules establishing and governing transmission information networks and standards of conduct. The Commission is issuing this final rule in tandem with its final rule on Open Access Transmission and Stranded Costs (Open Access Final Rule).[1] This final rule applies to any public utility that offers open access transmission services under the Open Access Final Rule *pro forma* tariff. Under the Open Access Final Rule, the open access *pro forma* tariff may be used by wholesale transmission customers and by retail transmission customers that are able to receive unbundled retail transmission either voluntarily from the public utility or as a result of a state retail access program.

This final rule is being issued after a review of the comments filed in response to the Commission's notice of proposed rulemaking issued in this proceeding on December 13, 1995 (RIN NOPR).[2]

This final rule becomes effective on July 9, 1996. By November 1, 1996, all affected public utilities must file procedures with the Commission that will enable customers and the Commission to determine whether they are in compliance with the standards of conduct requirements contained herein.

Additionally, under this final rule, each public utility as defined in section 201(e) of the Federal Power Act, 16 U.S.C. 824(e) (1994), (or its agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce (each Transmission Provider) must develop or participate in an Open Access Same-time Information System (OASIS).[3] This final rule establishes Phase I OASIS rules that require the creation of a basic OASIS.[4] The basic OASIS required by this final rule must be in place and operational by November 1, 1996. The development of OASIS requirements will continue in Phase II, during which the Commission will develop the requirements for a fully functional OASIS.

While the final rule set forth in this order is consistent with the proposal described in the RIN NOPR, it also resolves certain issues that were described in the RIN NOPR but left undecided, and adds clarifications and revisions, as suggested by the comments. As proposed in the RIN NOPR, the final rule describes what information must be provided on an OASIS, how an OASIS must be implemented and used, and contains a code of conduct applicable to all transmission providing public utilities.

As proposed in the RIN NOPR, we are issuing this final rule along with a separate document entitled *OASIS Standards and Communication Protocols (Standards and Protocols)* to help ensure that each OASIS will provide information in a uniform manner. However, the standards and protocols are not yet complete. Consequently, we are inviting the How Group[5] to submit an additional report, on or before May 28, 1996, to help us resolve these deficiencies. We will also hold a technical conference on June 17, 1996 to resolve any remaining issues and to allow input from interested persons. We will issue a revised *Standards and Protocols* document as soon as possible thereafter.

We are moving promptly to complete the standards and protocols to ensure that the OASIS will be operational and in compliance with this final rule by November 1, 1996. In selecting this date, we have balanced the need to have a functional system of fair and non-discriminatory information in place to support the Open Access Final Rule against the comments that argued that implementation of an OASIS could not be accomplished in 60 days and to avoid implementation during the peak winter or summer months.

II. Public Reporting Burden

The final rule requires Transmission Providers to participate in an OASIS designed to provide open access transmission users and potential open access transmission users with information by electronic means about available transmission capacity and prices.

The RIN NOPR contained an estimated annual public reporting burden associated with a final rule consistent with the RIN NOPR. In response to the RIN NOPR, NRECA[6] filed comments with the Commission that argued that the Commission's estimated public reporting burden should have taken into account that Question 45 of the RIN NOPR asked whether OASIS rules should be *extended* to apply to non-public utilities that own or control facilities used for the transmission of electric power in interstate commerce.[7] Based on this inquiry, NRECA argued that the public burden estimate should have been based on the assumption that the proposed OASIS rules would be extended to apply to non-public utilities (even though this was not proposed by the Commission).

The Commission's task in preparing a public burden estimate at the NOPR stage was to estimate the annual public reporting burden associated with a final rule consistent with the RIN NOPR. This is what the Commission did. An

[1] *See* Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Final Rule, FERC Stats. & Regs. ¶ 31,036 (April 24, 1996); this document is being published concurrently in the Federal Register.

[2] Real-Time Information Networks and Standards of Conduct, Notice of Proposed Rulemaking, 60 FR 66182 (December 21, 1995), FERC Stats. & Regs. ¶ 32,516 (December 13, 1995).

[3] In the notice of technical conference that initiated this proceeding, *see infra* n. 12, we chose the term ''Real-Time Information Network'' to describe the electronic information system envisioned by that notice. We invited comments on whether we should substitute another term in place of RIN. In response, a number of commenters suggested that ''RIN'' was not a suitable name for the electronic information network envisioned by the RIN NOPR, mainly because while some RIN postings may be made ''real-time'' most will not and that, therefore, RIN is a misnomer.

After a review of suggested replacements presented in the comments, we will abandon the name ''RIN'' in favor of Open Access Same-time Information System, suggested by Virginia Electric Power Company (VEPCO), for several reasons. First, as noted above, the information system being developed in this proceeding actually will be a ''same-time'' information system, and not a ''real-time'' system. Second, VEPCO correctly points out that the system will be part of an existing network (the Internet) and not a new network. Third, the name ''OASIS'' highlights that the system relates to open access.

[4] Any entity may, for good cause, seek a waiver of the requirements established by this final rule, either as to the creation of an OASIS or for reporting requirements.

[5] *See, infra,* n. 13.

[6] Attached to this document is a list of the commenters and the abbreviations used to designate them. Several of the comments were filed late. We, nevertheless, will consider these comments.

[7] NRECA also submitted a letter to the Office of Management and Budget (OMB) that raised the same issue.

estimate based on deviations from the NOPR proposal, as NRECA suggested, would have been inappropriate. At the same time, however, by asking Question 45, we identified the issue and gave the commenters an opportunity to be heard before making a final decision.

Our final rule, like the RIN NOPR, applies only to public utilities, and not to non-public utilities. However, as discussed in this order and as commented upon by various non-public utilities, in the Open Access Final Rule we are including a reciprocity provision in public utility open access tariffs under which all those who elect to take service under the open access tariff (including non-public utilities) will have to offer reciprocal service including an information network, unless they are granted a waiver of the reciprocity provision in the tariff.[8] Consequently, we have increased the estimate of number of respondents in this rulemaking to reflect the additional burden on those non-public utilities that seek service under open access tariffs. However, this is offset by our current expectation that there will be far fewer OASIS sites than we originally anticipated in the RIN NOPR. The How Group estimates there will be between 20–35 OASIS sites nationwide.[9] Using the higher number, the burden of running each OASIS will be shared, on average, by four respondents. This is reflected in the burden hour and cost estimates.

Our burden hour and cost estimates include the information gathering requirements imposed on public utilities that do not develop their own OASIS. Additionally, we have refined our estimate of the annual public reporting burden to account for revisions that this final rule makes to the RIN NOPR.

Estimated Annual Burden:

Data collection	No. of respondents	No. of responses	Hours per response	Total annual hours
Reporting	140	1	1879	263,060
Recordkeeping	140	1	418	58,520

Total Annual Hours for Collection (Reporting + Recordkeeping, (if appropriate)) = 321,580.
Data collection costs: The Commission projects the average annualized cost per respondent to be the following:
Annualized Capital/Startup Costs—$47,500.
Annualized Costs (Operations & Maintenance)—$142,250.
Total Annualized Costs—$189,750.

Internal Review

The Commission has reviewed the collection of information required by this final rule and has determined that the collection of information is necessary and conforms to the Commission's plan, as described in this final rule, for the collection, efficient management, and use of the required information. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the information burden estimate set forth above.[10]

Persons wishing to comment on the collections of information required by this final rule should direct their comments to the Desk Officer FERC, Office of Management and Budget, Room 3019NEOB, Washington, D.C. 20503, phone 202–395–3087, facsimile: 202–395–7285 or via the Internet at hillier_____t@a1.eop.gov. Comments must be filed with the Office of Management and Budget within 60 days of publication of this document in the Federal Register. A copy of any comments filed with the Office of Management and Budget also should be sent to the following address at the Commission: Federal Energy Regulatory Commission, Information Services Division, Room 41–17, 888 First Street, NE., Washington, DC 20426. For further information, contact Michael Miller, 202–208–1415.

III. Discussion

A. Background

This proceeding began with the issuance of our proposed Open Access rule (Open Access NOPR) [11] and a notice of technical conference to consider whether a RIN (now an OASIS) or some other option would be the best means to ensure that potential customers of transmission services could obtain access to transmission service on a non-discriminatory basis. [12] The notice of technical conference was followed by procedures and input (described in the RIN NOPR) that led to the issuance of the RIN NOPR.

Open access non-discriminatory transmission service requires that information about the transmission system must be made available to all transmission customers at the same time. This means that public utilities must make available to others the same transmission information that is available to their own employees and that is pertinent to decisions they make involving the sale or purchase of electricity. The RIN NOPR suggested requirements representing the first steps towards accomplishing these objectives.

The RIN NOPR addressed four main issues: the types of information that need to be posted on an OASIS; technical issues concerning the development and implementation of an OASIS; the development of a basic OASIS in Phase I and the development of a fully functional OASIS in Phase II; and proposed standards of conduct to prevent employees of a public utility (or any of its affiliates) engaged in marketing functions from obtaining preferential access to OASIS-related information.

[8] As explained in the Open Access Final Rule, non-public utilities that do not want to meet the reciprocity condition may choose not to take service under an open access tariff. In that circumstance, the public utility may, if it chooses, voluntarily provide transmission service on a unilateral basis to the non-public utility.

[9] How Group comments at 19.

[10] *See* 44 U.S.C. § 3506(c).

[11] *See* Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice and Supplemental Notice of Proposed Rulemaking, 60 FR 17662 (April 7, 1995), FERC Stats. & Regs. ¶32,514 (March 29, 1995).

[12] Real-Time Information Networks, Notice of Technical Conference and Request for Comments, 60 FR 17726 (April 7, 1995).

The Commission's consideration of the first two of these issues relied heavily on the efforts of two industry-led working groups that presented recommendations to the Commission.[13]

Additionally, the RIN NOPR invited commenters to address specific questions on various issues and invited comments generally on the entire proposal.

As discussed in the RIN NOPR, the handling of various types of information that might be posted on an OASIS depends on substantive determinations being made in the Commission's Open Access rulemaking proceeding.[14] For this reason, the RIN NOPR attempted to identify the issues that might be affected by decisions that would be made in the Open Access rulemaking and invited comment on the mechanics of implementing whatever determinations ultimately would be reached in the Open Access rulemaking, without attempting to prejudge the merits of the underlying legal and policy issues.

Additionally, the RIN NOPR included (as Appendix ''C'') a set of upload and download templates for comment to ensure that all data definitions are the same and that the information presented on the OASIS will be uniform and clearly understood.

The Commission's RIN NOPR, issued on December 13, 1995, invited comments on enumerated questions, along with general comments. Comments were filed by over 100 commenters. These comments were generally favorable to the OASIS concept, although numerous disagreements remained as to the details. The comments will be discussed below on an issue-by-issue basis.[15]

In the RIN NOPR, we invited the two industry-led working groups to continue their efforts to reach consensus and to report to us on their progress. On March 7, 1996, the How Group submitted a report giving proposed revisions to their original report.[16] The How Group also submitted a report on April 15, 1996 making recommendations on additional issues on which the group had reached consensus.

B. Summary of the Regulations and Their Implementation

The Commission is issuing this final rule with the Open Access Final Rule to implement the legal and policy determinations being made in the Open Access Final Rule.[17] This final rule contains three basic provisions that, taken together, will ensure that transmission customers have access to transmission information enabling them to obtain open access transmission service on a non-discriminatory basis. This final rule is necessary, therefore, to meet the legal requirement, discussed in the Open Access Final Rule, that the Commission remedy undue discrimination in interstate transmission services by public utilities.

The first provision establishes standards of conduct. These standards are designed to ensure that a public utility's employees (or any of its affiliates' employees) engaged in transmission system operations function independently of the public utility's employees (or of any of its affiliates' employees) who are engaged in wholesale purchases and sales of electric energy in interstate commerce. Such separation is vital if we are to ensure that the utility does not use its access to information about transmission to unfairly benefit its own or its affiliates' sales. Entities subject to these rules are to achieve compliance with the standards of conduct by November 1, 1996.

The second provision sets out basic rules requiring that jurisdictional utilities that own or control transmission systems set up an OASIS. Under these rules, the utilities are required to provide certain types of information on that electronic information system as to the status of their transmission systems and are required to do so in a uniform manner. With these requirements, we are opening up the ''black box'' of utility transmission system information. When in place, the OASIS will allow transmission customers to determine the availability of transmission capacity and will help ensure that public utilities do not use their ownership, operation, or control of transmission to deny access unfairly. Entities subject to this rule are to have a basic OASIS, meeting the requirements of this final rule, in operation by November 1, 1996.

The third component involves the various standards and protocols referenced in the regulations that are necessary to ensure that the OASIS system presents information in a consistent and uniform manner. As proposed in the RIN NOPR, this final rule references a publication entitled *OASIS Standards and Communication Protocols*.[18] This publication contains the above-mentioned standards and communication protocols. The publication details the Phase I requirements for technical issues related to the implementation and use of an OASIS (*i.e.*, a compilation of OASIS standards and communication protocols). Because of their level of detail, the standards and protocols referenced in the regulations will be contained in the *Standards and Protocols* document and will not be set out in the Code of Federal Regulations.

In developing the standards and protocols, we have been greatly assisted by the industry. However, more work needs to be done before the necessary standards and protocols are complete. For this we will again look to the industry and its working groups. The Commission believes a standard or uniform set of protocols is essential. The industry is best situated not only to develop the necessary standards but to develop them where possible with a consensus. Consequently, we are asking the How Group to provide us with

[13] The North American Electric Reliability Council (NERC) acted as a facilitator for an industry-led independent working group, representing diverse interests, to help participants reach consensus, and to help them prepare a report to the Commission on what information should be posted on a RIN (the ''What Group''). The Electric Power Research Institute (EPRI) facilitated a similar working group (the ''How Group'') that sought consensus on how to implement a system that would accomplish these objectives. Both groups submitted reports to the Commission describing their progress in reaching consensus on their respective issues. As explained in the RIN NOPR, after determining that the working groups had balanced representation from diverse interests and had operated in an open, inclusive manner, the Commission used the working groups' recommendations as the starting point for developing the RIN NOPR.

A fuller description of the working groups' composition and activities is contained in the RIN NOPR and in the reports that those groups submitted to the Commission for its review (attached to the RIN NOPR as Appendices ''A'' and ''B'' and made publicly available at the Commission's offices and through the Commission Issuance Posting System (CIPS)).

[14] For example, the information about ancillary services that must be posted on an OASIS depends on what ancillary services a public utility must provide. Likewise, the information about discounts that must be posted on an OASIS depends on whether discounting is allowed.

[15] In the discussion that follows, our references to comments are illustrative and not inclusive. While we have intended to identify all of the major issues raised by the commenters, we have not attempted to identify all commenters in instances where more than one comment makes the same point.

[16] The participants in the How Group submitted a report entitled *Consensus Comments of the Wholesale Electric Power Industry* on behalf of the ''industry management process (interim) on how to implement transmission services information networks?''

[17] For example, a number of smaller public utilities and non-public utilities have argued that they should be exempted from the OASIS requirements. The Open Access Final Rule provides that public utilities may seek waivers of some or all of the requirements of the Open Access rules. This would include the OASIS requirement. Similarly, the Open Access Final Rule provides that non-public utilities may seek waivers of the tariff reciprocity provision as applied to them.

[18] This title differs slightly from the title we suggested for this document in the RIN NOPR. We are making this change to reflect more accurately the contents of the document as it has evolved.

additional recommendations on those technical issues remaining to be resolved. After receiving this report, we will hold a technical conference. In the meantime, to enable utilities to begin the process of implementing their OASIS, we will publish the standards and protocols that have been developed to date.

We must also provide for the contingency that, over time, the standards and protocols may need to be revised. To this end, NERC, in its comments, proposed to continue the industry-based process for developing OASIS requirements begun by the two industry working groups. NERC argued that the Commission should abandon its intention to approve standards developed by industry-wide consensus and to make decisions in those areas where consensus is not achieved. Instead, NERC argued that the Commission should authorize an industry group, facilitated by NERC and EPRI, to set and enforce detailed standards under broad policy guidelines fixed by the Commission.

As we have needed the contributions of the industry to develop the standards and protocols, we will continue to need that assistance in the future to develop a consensus wherever possible. We need to strike a balance between standardization to make OASIS work and encouraging innovation. To this end we encourage all industry participants to continue seeking consensus and reporting proposals to the Commission for our consideration. We welcome the continued work of *all* industry participants on revising and improving standards and establishing appropriate methods for recommending standards in the future. We will continue to give careful consideration to all consensus recommendations presented by the industry group(s), provided that they continue to invite balanced participation in an open process.

However, we reject entirely the notion that the Commission need not approve the *Standards and Protocols* and that these matters can be left to the industry for implementation and self-policing. Although we continue to seek industry consensus, the Commission must reserve final decisions to itself. We cannot turn over the process of approving and enforcing OASIS requirements to the industry. The Commission does not believe that resolution of the outstanding issues or future changes will occur more quickly without Commission oversight.[19] Nor do we believe that merely by announcing broad policy guidelines we would be creating a mechanism that would be sufficient to allow the Commission to revise regulations quickly. Accordingly, we will not abdicate our responsibility to decide these issues ourselves; nor shall we delegate responsibility for making these decisions to anyone else.

With respect to the as yet unresolved technical issues, we invite the How Group to report to us on or before May 28, 1996 on these issues (and to attach any comments it has received from any interested person with opposing views). Prior to issuing a revised *Standards and Protocols* document, we will hold a technical conference on these issues on June 17, 1996. This short time frame is necessary if the OASIS is to be properly operational by November 1, 1996.

The Commission recognizes that the standards and protocols necessarily will evolve over time. The Commission is committed to a process for reviewing and, if necessary, revising and improving the *Standards and Protocols* on a regular basis after implementation. We are sensitive to the fact that business practices and technology will continue to change under open access and that a mechanism to make changes to the regulations and to the accompanying standards and protocols on an expedited basis may be needed. It would be premature at this time, however, to determine the appropriate mechanism for making such changes, because the method could vary depending on the type of change contemplated. In filing its report, we ask that the How Group advise us on this issue. We will welcome discussions and comments on mechanisms for revising the standards and protocols on an ongoing basis at the June 17, 1996 technical conference.

In the sections that follow, we discuss, section-by-section, the regulations we are adopting with this final rule; how the costs of implementing the requirements of these regulations are to be recovered; and the details of implementation.

C. Section 37.1—Applicability

This section is unchanged substantively from what we proposed in the RIN NOPR. As proposed previously, the rules in Part 37 apply to any public utility that owns or controls facilities used for the transmission of electric energy in interstate commerce.[20]

In proposing these regulations, we stated that issues relating to potential gaps in providing comparable open access to wholesale transmission services or to transmission information that may arise because the requirements do not apply to non-public utilities would be addressed in the Open Access rulemaking proceeding. We also invited comment on whether the Commission should extend OASIS requirements to non-public utilities that own or control facilities used for the transmission of electric energy in interstate commerce (Question 45) and on whether the reciprocity condition of the proposed Open Access rule dictates that a non-public utility should have an OASIS (Question 46).

Comments

The responses to Question 45 split along industry lines. Generally, public utilities subject to OASIS rules advocated that the Commission should impose OASIS requirements on non-public utilities. They argued that applying OASIS requirements to non-public utilities would promote competition and a ''level playing field.'' These commenters argue that all companies should pay the costs of developing and operating an OASIS and should be required to divulge information to their competitors on it.

Along these lines, Allegheny argued that, in order to provide a level playing field between public utilities and their competitors, the proposed standards of conduct should be expanded to include personnel of any entity that trades on an OASIS. Allegheny suggested, therefore, that the standards of conduct be rewritten to be applicable to non-public utilities through a requirement that they sign confidentiality agreements as a condition of obtaining access to OASIS.

Those favoring applying OASIS rules to non-public utilities argued that a significant portion of the wholesale transmission market is owned by non-public utilities (ConEd estimates that non-public utilities, excluding cooperatives, control about 25 percent of the circuit miles of transmission lines nationwide). They argued that, without information about these lines, accurate calculations of available transmission capability cannot be made. However, those advocating that the Commission should assert jurisdiction over non-public utilities were divided between those who maintained that the Commission has authority to do so directly under § 311 of the Federal

[19] To the contrary, our experience with the natural gas pipeline industry persuades us that an expedited schedule is more likely with active Commission oversight than otherwise.

[20] We are, however, modifying this provision to clarify that it is intended to include public utilities that ''operate'' facilities used for the transmission of electric energy in interstate commerce. We are also clarifying that these regulations apply to transactions performed under the *pro forma* tariff required in Part 35 of the Commission's regulations.

Power Act (FPA)[21] and those who maintained that the Commission does not have such authority. The latter group suggested that the Commission's authority is not clearcut and, to avoid needless delay and litigation, the Commission should rely on the reciprocity condition in the *pro forma* tariffs to extend OASIS requirements to non-public utilities.[22] ConEd argued that we should state that compliance with OASIS requirements is required by both § 311 and reciprocity.

The larger non-public utilities argued that, while the Commission lacks authority to impose OASIS rules under § 311 of the FPA, they nevertheless will voluntarily comply with the rules because this would be in their own best interest. By contrast, a number of small non-public utilities argued that they should be exempt from OASIS rules, particularly the standards of conduct, for the same reasons that smaller public utilities argued that they should be exempted from the requirements of the Open Access Final Rule. The smaller non-public utilities stressed that they do not ''control'' many of their transmission lines and that many of their lines lack commercial interest. They recommended the development of a joint or regional OASIS that would make participation in an OASIS easier and argued that, as to smaller non-public utilities, the rules requiring a separation of functions are unduly burdensome and their scant benefits would be outweighed by their costs to consumers.

NRECA argued that the availability of transmission service under § 211 of the FPA is sufficient to prevent abuses. By contrast, Com Ed argued that Commission orders in § 211 proceedings come too late to prevent abuses.

In Question 46 of the RIN NOPR, we asked whether, based on reciprocity, we should require non-public utilities to develop or participate in an OASIS.[23] The responses to this question generally are split along the same lines as the responses to Question 45, with non-public utilities pointing out that most would participate voluntarily in an OASIS because it would be in their best interest to do so.

APPA asserted that voluntary participation would suffice to accomplish the Commission's goals and seeks assurance that compliance with OASIS requirements by non-public utilities would be deemed by the Commission to satisfy the reciprocity condition in the *pro forma* tariffs. APPA also asserted that participation in a regional OASIS would make compliance easier for non-public utilities and would help them deal better with operational issues such as parallel flows. At the same time, NE Public Power District argued that, although it is willing to participate in an OASIS voluntarily, the Commission lacks authority to compel publicly-owned non-public utilities to comply with OASIS regulations.

In contrast, a number of public utilities maintained that non-public utilities cannot provide comparable open-access non-discriminatory service unless they comply with the same OASIS rules as do public utilities. PJM argued that, although public utilities and non-public utilities differ in their ownership, this does not provide a rational basis to exclude non-public utilities from participation in an OASIS. Carolina P&L argued that the same concerns that motivated the Commission to propose the standards of conduct dictate that the rules should apply equally to non-public utilities.

Others argued that, if non-public utilities need not comply with the same OASIS rules applicable to public utilities, the non-public utilities would have the benefit of an uneven playing field that would give them a competitive advantage. Along these lines, EGA argued that, in pursuing a competitive wholesale market, the Commission should apply OASIS rules equally to all entities that own wholesale transmission facilities. Mid-American stressed the need for reciprocity by pointing out (as others did in response to Question 45) that a significant portion of wholesale transmission facilities nationwide, including some in pivotal areas, are owned by non-public utilities. VEPCO urged that any entity that owns transmission facilities, is affiliated with an entity that owns transmission facilities, controls transmission facilities through a lease or contract, or signs a contract for transmission services, should be required to establish or participate in an OASIS that is compatible with the industry standards established by the Commission in the final rule in this proceeding as a condition of being eligible to use a Transmission Provider's OASIS.

OK Com stated that it would support the Commission's assertion of jurisdiction over non-public utilities, provided that the Commission makes a finding that the non-participation of a transmission owning entity in an OASIS would have a substantial detrimental impact on potential customers attaining open-access non-discriminatory service throughout the Nation. Com Ed argued that the Commission needs to ensure that non-public utilities do not circumvent the rule by making purchases and sales through intermediaries.

Larger non-public utilities, such as Public Generating Pool, suggested that the participation of larger non-public utilities is much more important, in terms of promoting competition in the wholesale market, than is participation by smaller non-public utilities, whose systems are predominantly small distribution systems that are not essential to the larger regional power market. Public Generating Pool proposed that small non-public utilities should be able to seek an exemption and that regional transmission groups should decide whether it is necessary for a small non-public utility to participate in the regional OASIS. Public Generating Pool also suggested that, if the Commission prefers, decisions as to who is required to implement an OASIS could be based on objective factors, such as market share or concentration. Other non-public utilities, such as Seattle and Tallahassee, stress the need for flexibility (in providing sufficient time for compliance and in allowing deviations from the rule) in any requirement that non-public utilities make changes to their system.

Discussion

After reviewing these comments we have concluded that we will not directly assert jurisdiction over non-public utilities under § 311 of the FPA to ensure compliance with OASIS requirements. We will, instead, rely on the reciprocity provision of the *pro forma* tariff that requires a non-public utility to offer comparable transmission service to the Transmission Provider as a condition of obtaining open access service. If a non-public utility chooses to take open access service, and therefore is subject to the tariff reciprocity condition, it will need to meet the OASIS requirements in new Part 37, unless the Commission grants a waiver of this condition. Although, as pointed out by ConEd, non-public utilities control a significant percentage of the circuit miles of transmission lines nationwide, and fully accurate calculations of available capacity on public utilities' lines cannot be made without information about these lines,

[21] 16 U.S.C. § 825j. Section 311 authorizes the Commission to obtain information (and conduct appropriate investigations) about, among other matters, the transmission of electric energy throughout the United States, regardless of whether such transmission is otherwise subject to the Commission's jurisdiction, and to report to Congress the results of any investigations it carries out under the authority of this provision.

[22] *See* discussion of Question 46, *infra*.

[23] The discussion of questions 45 and 46 by commenters often overlapped.

we believe reciprocity provides a sufficient incentive for non-public utilities to meet the OASIS requirements imposed on public utilities.

We note that in our Open Access Final Rule we have concluded that certain of the requirements we are imposing on public utilities may not be appropriate for small utilities. This conclusion applies equally to the treatment of small public utilities and small non-public utilities. Accordingly, we have established a mechanism in the Open Access proceeding that allows small public utilities and small non-public utilities to seek waivers based on the same criteria.[24]

D. Section 37.2—Purpose

Section 37.2 sets out the fundamental purpose of this part—to ensure that all potential customers of open access transmission service have access to the information that will enable them to obtain transmission service on a non-discriminatory basis. Comments in response to the RIN NOPR did not take issue with the proposed language of § 37.2 and we are adopting this provision largely without change.

We wish to clarify, however, that while the OASIS requirements imposed by this final rule establish a mechanism by which Transmission Customers may reserve transmission capacity, they do not require the replacement of existing systems for scheduling transmission service and conducting transmission system operations at this time. We believe that it may be appropriate to include energy scheduling as part of the OASIS requirements developed for Phase II. In the meantime, if we conclude that an existing system is operated in an unduly discriminatory manner, we will pursue changes to such a system in a separate proceeding.

E. Section 37.3—Definitions

This section defines six terms used throughout this Part—''Transmission Provider'', ''Transmission Customer'', ''Responsible Party'', ''Resellers'', ''Wholesale Merchant Function'', and ''Affiliate''. The comments in response to the RIN NOPR did not take issue with the proposed definitions.[25] Consequently, this final rule adopts these definitions largely without change. To prevent confusion, the definition of Transmission Customer has been revised to include potential customers, *i.e.*, those who can execute service agreements or can receive services as well as those who actually do so. And, we have modified the definition of ''Affiliate'' to more closely track provisions of the FPA and the Public Utility Holding Company Act.

F. Section 37.4—Standards of Conduct

This section sets out the standards of conduct necessary to ensure that Transmission Providers do not use their unique access to information unfairly to favor their own merchant functions, or those of their affiliates, in selling electric energy in interstate commerce. Although preserving the substance of what was proposed, the final rule has been reorganized.

Paragraph (a) sets out the general rules that require the separation of transmission and merchant functions and that recognize in emergency circumstances system operators may take whatever steps are necessary to keep the system in operation.

Paragraph (b) sets out the specific rules governing employee conduct under five headings covering prohibited practices, transfers of employees, access to information, disclosure, and conduct in implementing tariffs. These provisions correspond to elements of paragraph (a), as well as paragraphs (b) through (h) and (j) of the standards proposed in the RIN NOPR.

Paragraph (c) requires that there be written procedures implementing the standards of conduct and that these must be kept in a public place and filed with the Commission. Paragraph (c) corresponds to paragraph (k) of the standards proposed in the RIN NOPR.

In the RIN NOPR, the Commission proposed standards of conduct for public utilities patterned after those promulgated for natural gas pipelines.[26] The proposed standards of conduct would require Transmission Providers to separate their wholesale merchant functions (*i.e.*, wholesale purchases or wholesale sales of electric energy in interstate commerce) from their wholesale transmission system operations and reliability functions. Employees performing wholesale merchant functions would be required to obtain information on wholesale transmission services only through an OASIS, on the same basis available to all other OASIS users. The standards of conduct were intended to prevent employees of the Transmission Provider that perform wholesale merchant functions or employees of any affiliate from having *preferential* access to any relevant information about the Transmission Provider's wholesale transmission availability and costs, or uses or possible uses of the Transmission Provider's transmission system by non-affiliates.[27]

We accompanied this proposal with two questions that asked whether the proposed standards of conduct should be modified and whether they sufficiently addressed functional unbundling (Questions 41 and 42). We also asked whether our proposal might interfere with system reliability (*see* Question 43).

The responses basically fell into three categories.[28] First, a number of smaller public utilities argued that they should be granted waivers (or be deemed exempt) from the proposed standards of conduct because these standards would compel them to hire additional staff not justified by their small market share or by the small revenues they derive from providing wholesale transmission services. These comments suggested that the standards should not apply to public utilities that lack operational control over the facilities used for wholesale transmission service, or to public utilities that do not exceed given thresholds for market share, percent of revenues, or total revenues from wholesale transmission services.

Second, a number of large utilities basically were satisfied with the proposed rules and offered specific suggestions for revisions. Third, commenters raised the issue of whether to require the separation of generation

[24] Open Access Final Rule at section IV.K.

[25] MidAmerican Energy suggested, however, that a definition for ''Transmission System Operator'' be added. We will not do so because we do not use this term anywhere in the OASIS regulations. MidAmerican's purpose in making this suggestion may have been to exclude the posting on the OASIS of transactions involving the use of transmission for purchases made for native load (this issue was also brought up by CCEM, EGA, MidAmerican, NYPP, and NIEP). We address the issue of native load purchases in the Open Access Final Rule.

[26] In the RIN NOPR, the proposed standards of conduct were set out in § 37.6. *See* RIN NOPR text at section III.E (60 FR at 66196) and the proposed regulation at 18 CFR § 37.6 (60 FR at 66199). We are renumbering this provision as § 37.4 in this final rule.

[27] Because the Open Access Final Rule pro forma tariff may include certain retail transmission customers, this final rule's OASIS information requirements will apply to applicable retail as well as wholesale services and information.

[28] Among the over 100 comments filed, only Dayton P&L, among public utilities, questioned the Commission's underlying authority to mandate control room unbundling. Dayton P&L's short conclusory statements in this proceeding were not accompanied by even a cursory explanation of its reasoning or by any legal analysis or supporting citations.

Although Dayton P&L offered no support for its position in this proceeding, it did (along with other parties) devote extensive discussion to the more general issue of the Commission's authority to order open access transmission in its initial comments in the Open Access rulemaking proceeding. We reject Dayton P&L's unsubstantiated conclusion, urged in this proceeding, that we lack authority to order control room unbundling for the same reasons that we reject their more general and more extensive arguments on the Commission's authority in the Open Access Final Rule. *See* Open Access Final Rule at section IV.B.

and transmission functions.[29] We discuss these three categories below.

1. Requests by Smaller Public Utilities for Waivers From the Standards of Conduct

Turning first to the arguments of smaller public utilities that they should be exempt from the standards of conduct, we note that this issue also arose in the Commission's Open Access rulemaking proceeding. As described in the Open Access Final Rule, we will publish a list of jurisdictional public utilities that must comply with these rules. At the same time, we establish a mechanism that allows small public utilities to seek a waiver. In appropriate circumstances, the Commission would waive some or all of the Open Access requirements, subject to future reconsideration as warranted by circumstances.[30]

A related issue involves the concerns of small non-public utilities about their obligation under the reciprocity condition. We have decided in the Open Access rulemaking proceeding that we would use these same criteria to decide whether a small non-public utility should be granted a waiver from all or part of the reciprocity condition contained in public utility open access tariffs. Such waivers could be sought of the requirements to have open access tariffs, provide ancillary services, establish an OASIS, or separate functions.

A full explanation of the waiver mechanism is contained in the Open Access Final Rule.[31] We will use these same standards to determine whether small public utilities have complied with the OASIS requirements and to determine whether small non-public utilities have met their contractual obligation to comply with OASIS requirements as a condition of service under open access tariff reciprocity provisions.

2. Suggested Revisions to the Standards of Conduct and Timing

For the most part, we have adopted the standards of conduct as proposed, making technical and conforming revisions. In a few instances, in response to comments, we have made substantive changes. These changes, and the suggestions that led us to make them, are discussed below, along with some suggestions that we rejected.

1. As proposed, the regulations would prohibit preferential access to the system control room and ''other facilities of the public utility'' that differs from the access available to other potential transmission users. AEP suggested that it is not clear whether this was intended to restrict access to *all* other facilities or is meant to restrict access to other *similar* facilities, (*i.e.*, those facilities that, like the control room, are involved in transmission operations and reliability functions). Consistent with this latter interpretation, AEP suggested that the restriction be modified to apply to the system control room and ''similar facilities used for transmission operations or reliability functions.'' We agree with AEP's interpretation of the scope of this restriction and adopt the suggested revision in section 37.4(b)(1)(ii) of the final rule.

2. Section 37.4(c) of the proposed standards of conduct would prohibit contacts (off OASIS) between employees of the public utility engaged in transmission system operations and employees of the public utility engaged in wholesale marketing functions, and employees of any affiliate no matter how employed. AEP, Com Ed, and Ohio Edison argued that this provision is too broad and would exclude contacts between transmission system operators and employees of affiliates engaged in various activities, many of which are unrelated to a public utility's merchant functions. For example, an energy services subsidiary might be engaged in building a power plant in a foreign country. AEP argued that there would be no reason to deny employees engaged in such an activity access to utility personnel involved in transmission or reliability functions. Com Ed suggested that this provision should be modified to prevent contacts between system operators and employees engaged in wholesale marketing functions, regardless of whether those marketing employees are engaged in those activities on behalf of either the utility or its affiliates. Thus, under this argument, contacts between system operators and affiliate employees not engaged in wholesale marketing functions would not be prohibited.

We agree with AEP, Com Ed, and Ohio Edison that our proposed standards of conduct were overly broad because they prohibited contacts between system operators and affiliate employees engaged in functions completely unrelated to a public utility's wholesale power and energy marketing functions. We will revise the proposed standards of conduct accordingly.

AEP also argued that employees of the affiliate may be involved in the wholesale merchant function, but not in the utility's market area. For example, an employee of an affiliate might be involved in a different geographic area, far from the system's transmission grid. AEP argued that there would be no need to isolate such activities from the utility's transmission operations. To cover such situations, AEP suggested that the language be modified to read ''employees of any affiliate of the public utility, to the extent that such employees are engaged in wholesale merchant functions in the utility's market area.''

We reject AEP's suggestion. Although public utilities may still have the ability to exert market dominance in particular markets, they also will now have the ability to participate in transactions across the nation. We fully expect—and our experience with the WSPP demonstrates—that in the move to a competitive wholesale bulk power market, public utilities will have extensive market areas in which to make offers. Thus, there is no reason to limit the scope of the standards of conduct as recommended by AEP.

We also have clarified section 37.4(b)(3)(i) to explain that employees engaged in merchant trading functions must not have preferential access to any information about the Transmission Provider's transmission system that is not available to all users of an OASIS. However, the standards of conduct do not foreclose customers, including merchant employees, from obtaining information about the status of their particular contracted for transaction from Transmission Provider employees engaged in system operation and reliability functions. The information provided in status reports must present the same types of information, in the same level of detail, to any customer presenting a similar request. The standards do, however, preclude merchant employees from obtaining preferential access to information about

[29] A number of comments raised the issue of whether the OASIS regulations would promote ISOs (independent system operators) and whether participation in an ISO would exempt an entity from compliance with OASIS requirements. In this regard, a number of comments suggested that the proposed standards of conduct will result in the widespread transfer of transmission functions to the control of ISOs and predicted that the need for the standards of conduct will diminish as ISOs become more prevalent. In this context, IN Com supported the formation of ISOs, because this would reduce the need for state commissions to monitor functional unbundling and would help in resolving jurisdictional questions.

The concept of ISOs is addressed in the Open Access Final Rule. As to the prediction that the rise in the number of ISOs will make the standards of conduct unnecessary, or should offer a basis for an exemption from the standards of conduct, we would characterize the potential of ISOs somewhat differently. In our view, a properly constituted ISO could be a mechanism, not for an exemption, but as a means to comply with the standards of conduct.

[30] Open Access Final Rule at section IV.K.

[31] *Id.*

the Transmission Provider's system (not directly linked to their particular transaction) from any nonpublic source as well as market information acquired from nonaffiliated customers or potential nonaffiliated customers or developed by the Transmission Provider in its role as a Transmission Provider (except to the limited extent that this information is required to be posted on the OASIS).[32]

3. APPA argued that the rules should prohibit preferential treatment of wholesale purchases or sales by any utility. APPA interpreted the originally proposed language to mean that preferential treatment would be permitted, as long as the preference would not be extended to the public utility itself or an affiliate. APPA and Com Ed argued that preferential treatment of any wholesale customer over the interests of any other wholesale customer must not be allowed. Com Ed adds that absent clarification, relationships of reciprocal favoritism could develop in the industry, to the detriment of all other customers.

We find this contingency is possible. While the standards of conduct set guidelines for Transmission Providers and their affiliates in handling their wholesale merchant functions; public utilities are also governed by section 205(b) of the Federal Power Act. Section 205(b) prohibits public utilities from granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage with respect to any transmission or sale subject to the jurisdiction of the Commission. This provision remains in full force and effect and prohibits preferential treatment in transactions regardless of whether those transactions are specifically addressed in the standards of conduct.

4. In section 37.6(i) of the RIN NOPR we proposed that public utilities offer customers discounts comparable to those that the public utility offers to its own power customers or those of an affiliate. AEP suggested that this limitation on allowable discounts be expressly limited to discounts on wholesale transmission services. We agree and are revising this provision accordingly. Discounts for jurisdictional power sales are not governed by this final rule but by section 205(b) of the FPA and related precedent on power sales.

5. Allegheny suggested that the Commission should find that there will no longer be a presumption of discriminatory dealing between utility affiliates in generation and transmission services when network owners comply with the standards of conduct. Allegheny has presented no basis for making such a finding and we decline to do so.

6. Com Ed, Duke, and NEPOOL suggested that the proposed standards should not be interpreted to prevent employees of the utility engaged in wholesale marketing functions from obtaining information about their competitors from non-affiliated third party sources such as the trade press. Com Ed also suggested that the utility should be allowed freedom to give out information about its transmission functions off OASIS (*e.g.*, in briefings at public meetings) as long as the utility's wholesale marketing employees do not obtain *preferential* access to those forums. Ohio Edison suggested that the proposed standards of conduct should be revised to preclude only ''substantive access'' to the system control room. Ohio Edison argued that access for matters unrelated to transmission matters, such as training programs, should be permitted.

We have two points we wish to make regarding these related suggestions. First, we clarify that the rules do not prohibit access to information contemporaneously available without restriction to other members of the general public. (*See* section 37.4(b)(1)(ii) dealing with access to information). Second, these rules are intended to be interpreted consistent with common sense, prudence, and caution.

Our standards of conduct are intended to prevent preferential access to information related to transmission prices and availability by employees of the public utility or any affiliate engaged in wholesale merchant functions. Preferential access means that information is obtained from those with access to information about the public utility's transmission system operations that is not equally available to other customers. It is obvious, at least to us, that this does not bar wholesale merchant employees from reading the trade press or from sitting in the audience of a publicly-announced and available lecture delivered by the public utility's transmission operator or a third party in an open forum. However, the onus is on the public utilities subject to these standards to conduct their affairs in compliance with these rules, and they should exercise care and prudence in so doing.

We decline, therefore, to specify in these regulations whether, for example, a ''public meeting'' must be preceded by advance notice, to whom that notice must be provided, and what that notice would need to spell out. We do not believe that it would be appropriate to burden our rules with this kind of minutiae in a misplaced effort to anticipate every possible contingency. Such regulatory overkill is unwarranted and counterproductive. Moreover, those subject to the regulations may, like other members of the public, call the Enforcement Task Force Hotline to obtain informal advice on implementing the standards of conduct.

7. VEPCO suggested that, rather than prohibiting contacts between system operators and employees of the public utility and any affiliates engaged in wholesale merchant functions, the Commission could reach the same result by allowing system operators to disclose, through informal communications, information about the status of the transmission system, provided that they then post this information on OASIS.

We find this suggestion untenable. First, such disclosures would necessarily be posted after-the-fact, and thus the information would not be conveyed to all potential customers at the same time. Second, such a provision would be very difficult to enforce. Third, the same information could just as easily be divulged on the OASIS to all customers, rather than ''reported'' on the OASIS after-the-fact.

8. Com Ed suggested that the reference in subsections (a) and (d) of the proposed standards to ''reliability functions'' should be clarified to apply only to transmission functions and not to generation functions. We disagree. As discussed below, system operations and reliability functions include both transmission and generation functions.

9. Con Ed suggested that the standards of conduct should include a disclaimer that utilities will not be liable for the reliability or accuracy of data posted on the OASIS as an accommodation to third parties. We agree that the responsibility for assuring the reliability and accuracy of data supplied by third parties rests with those third parties and not with the public utility that posts this information on the OASIS as an accommodation. We do not, however, view this as a standard of conduct issue. Instead, we address this point in our discussion of what information is to be posted under § 37.6(g).

10. Ohio Edison suggested that posting the names of personnel transferring between departments would make these employees targets for recruitment by competitors. Notwithstanding this concern, we believe that this information must be posted on the OASIS to make possible

[32] *See* § 37.4(b)(4)(iii); *see* text accompanying n. 33, *infra*.

''gaming of the system'' through spurious revolving door tactics more visible.

11. Ohio Edison also suggested that the phrase in subsection (b) of the proposed standards ''* * * must rely upon the same information relied upon by the public utility's wholesale transmission customers'' should be modified to read ''* * * must have available only the same information available to the public utility's wholesale transmission customers.'' Ohio Edison argued that the Transmission Provider has no way of knowing what information its customers ''relied upon'' and that it should not be held to an undefinable subjective standard. We agree. Accordingly, we adopt Ohio Edison's suggestion in section 37.4(b)(3)(i) of the final rule and omit the phrase ''rely upon.''

12. Ohio Edison also suggested that if its suggestion (in the previous item) is adopted, then the language in section 37.4(b) beginning with the language in parenthesis becomes redundant and should be deleted. We disagree and will retain that language in section 37.4(b)(3)(ii) of the final rule. We believe the language adds necessary clarification.

13. Montana Power suggested that, if off-OASIS communications between the utility's system operators and wholesale marketing personnel are prohibited, these kinds of communications should also be prohibited between system operators and all transmission users. Montana Power would prefer, however, that these communications be permissible. Likewise, Duke suggested that we change the regulations so that if an employee of an unrelated third party calls the transmission-related employees, for example, to better understand the public utility's transmission system, such communications should be permitted to be conducted off the OASIS. Duke maintains that the free flow of information should not be discouraged so long as functional unbundling is implemented and affiliate abuse is avoided. NEPOOL suggested that the rules dictating the Transmission Provider's release of information should apply to all Transmission Customers, not just to the Transmission Provider's employees, as affiliates, engaged in wholesale merchant functions.

Our proposed standards of conduct were designed, and our final standards are being implemented, to prevent Transmission Providers from giving themselves an undue preference over their customers through the exchange of ''insider'' information between the company's system operators and employees of the public utility, or any affiliate, engaged in wholesale marketing functions. Thus, the rules place restrictions on preferential communications from the system operators to only those merchant employees. The rules were not designed to prevent system operators from having communications with third parties. We do not generally see this as an area that needs regulatory oversight. As discussed above, we have revised the regulations to ensure no discriminatory treatment and we remind public utilities subject to these regulations that section 205(b) of the FPA prohibits undue discrimination. This should suffice.

14. NUSCO suggested that the Commission should distinguish: (1) The functional separation of generation marketing related to operation of the transmission system and administration of transmission tariffs (which are relatively short-term activities); from (2) the coordination of marketing with the system planning function (a long-term activity encompassing both generation and transmission). Similarly, the FL Com is concerned that the standards of conduct might impede system reliability, and argued that marketers and system operators should be able to confer concerning the company's long-term planning activities that require knowledge about the company's generation and transmission systems. NEPOOL expresses similar concerns.

By contrast, Com Ed suggested that the proposed standards of conduct will not impair planning because, like a one-way street, they allow information to be conveyed from employees engaged in merchant functions to system operators, while at the same time prohibiting information to be conveyed in the opposite direction. Com Ed submitted that the inter-relationship between the areas of strategic planning, resource planning and long-range transmission planning require the flow of information to transmission personnel. Future acquisitions of capacity may constitute a resource taken into account in planning and may have an impact on the transmission system that needs to be accounted for by transmission planners. Thus, Com Ed argued that there should be no restriction on the flow of information about future purchases or sales from the merchant function to the transmission function, although restrictions on the flow of information to the merchant function should be adopted as proposed.

We agree with Com Ed that, as we proposed in the RIN NOPR, the flow of information, through the OASIS, from employees engaged in wholesale merchant functions to system operators should remain permissible, to allow proper system planning, while at the same time restricting information being conveyed off the OASIS from system operators to utility and affiliate employees engaged in wholesale merchant functions, to prevent preferential access to transmission information. Consequently, we reject the proposals offered by NUSCO, FL Com, and NEPOOL in this regard.

15. Omaha PPD argued that information regarding the scheduling of power transfers, economic dispatch, and economic conditions have nothing to do with the information that is needed regarding the availability of transmission capability. Omaha PPD suggested, therefore, that any information relating to economic operation or the commercial state of a utility be removed from the standards of conduct. By contrast, NUCOR suggested that, since economic dispatch is premised on real-time marginal production cost data and generating unit economics, the comparability standard mandates that utilities provide the same generation cost data to other market participants. Similarly, NUCOR argued that, because economic dispatch also is dependent on the economics of off-system purchases and sales, data pertaining to such purchases and sales also must be made generally available.

Except for postings for certain ancillary services, the RIN NOPR did not propose the posting on an OASIS of data on generation and we are not persuaded, at this juncture, to do more. Our decision is based on a balancing of the need for the information, the claimed commercial sensitivity of the information, and the desire to avoid, to the extent possible, having public utilities reporting generation data that their competitors may not be required to report.

16. VEPCO suggested that the regulations should prohibit system operators from disclosing information to wholesale marketing employees or other customers about the ancillary services offered by third parties because they are not permitted to disclose the same information about their companies' own products. VEPCO further suggested that the prohibition against discussing the companies' own products should be removed.

We find these suggestions inconsistent with the kinds of safeguards we are trying to provide through these standards of conduct. In any event, as discussed below in our discussion of items to be posted on the OASIS, we are requiring that this kind of information be posted on the OASIS, and thus companies will be able to get

their message out that these services are available.

17. Duke suggested that the proposed subsection dealing with the impartial application of tariff provisions should be revised to make clear it is the customer (and not the employees) who is to be treated on a fair and impartial basis. We agree and the final rule in section 37.4(b)(5)(ii) adopts this suggestion.

18. VEPCO suggested that the rules requiring a separation of functions should be suspended if additional employees trained in system operations (but normally assigned to marketing functions) should be needed to assist in handling system operation functions during emergencies affecting system reliability. VEPCO also suggested that the Commission should allow transmission and generation operators to engage in emergency energy transactions and hourly non-firm energy transactions.

It is not the purpose of these rules to compromise reliability. In emergency circumstances affecting system reliability, system operators may take whatever steps are necessary to keep the system in operation. Consequently, we are adding a provision to the standards of conduct that specifically grants system operators the authority to take whatever steps are necessary to maintain system reliability during an emergency, notwithstanding that this could otherwise constitute a violation of the standards of conduct. Transmission Providers will be required to report to the Commission and on the OASIS each emergency that resulted in any deviation from the standards of conduct, within 24 hours of such deviation. If we see a pattern of activities that suggested that ''emergencies'' are not authentic, we will take strong action against the offending public utilities.

Because we are adding a provision that allows actions to be taken in response to emergencies, we are deleting the phrase ''to the maximum extent practicable'' that had appeared in section 37.6(a) of the standards of conduct proposed in the RIN NOPR.

19. Continental Power Exchange argued that, just as merchant traders should be prohibited from access to the control center, system operators should be prohibited from access to the trading floor. United Illuminating agreed that separation of functions needs to apply to separation of transmission and customer supply functions. Continental Power Exchange also suggested that discounts should be offered unilaterally to all customers without prior notice and without two-way negotiation. Continental Power Exchange further suggested that short-term transactions should be deemed approved upon request, unless the utility specifically notifies the customer that the transaction will be denied. Continental Power Exchange argued that this would streamline the proposed procedures and make OASIS transactions faster and more manageable.

We will not, at this time, adopt Continental Power Exchange's suggestion to create an absolute prohibition against system operators having access to the trading floor because we are concerned about information divulged by system operators and not about information acquired by them. However, any non-public contacts between system operators and merchant traders creates the risk that there will be improper communications between these employees and the burden is on Transmission Providers subject to the standards of conduct to devise procedures that will prevent improper contacts. We expect, therefore, that the Transmission Providers themselves will devise procedures that will either prohibit or, at a minimum, severely restrict access to the trading floor by system operators.

As to Continental Power Exchange's other suggestions, we will not adopt these suggestions at this time, but may come back to them as the process evolves and the feasibility of back and forth negotiations is tested by experience.

20. SoCal Edison and Tucson Power suggested that, while the proposed 60-day deadline for filing procedures to implement the standards is adequate, the Commission needs to be flexible on implementing other changes, such as reconfiguring and relocating control rooms and other facilities, and training and recruiting new employees.

Although we originally proposed to require compliance with the standards of conduct starting 60 days from the publication of this final rule, on further consideration we have decided to put off the requirement that they be implemented until the implementation of OASIS, that is by November 1, 1996. As a practical matter, the standards of conduct cannot be implemented apart from the electronic communication systems of a functioning OASIS; the two work together. In addition, the extra time will permit utilities the opportunity to fully implement the requirements of the standards of conduct. Although the result will be a window of time during which open access transmission tariffs will not be supported by standards of conduct (or OASIS), we must recognize that the changes we are mandating for the industry cannot be implemented overnight; a transition period is required.

21. Finally, after a review of the comments, we have added an additional provision to the standards of conduct (section 37.4(b)(4)(iii) of the final rule) dealing with the posting of any additional market information developed by a Transmission Provider in its role as a Transmission Provider and shared with employees of its, or an affiliate's, merchant function.

We have expressed concern in a number of recent orders about the possibility of the dissemination of market information by a public utility with market-based rate authority.[33] To guard against the possibility of affiliate abuse, we have required such public utilities to commit in their codes of conduct with affiliates to share market information only if they make the same information publicly available to non-affiliates at the same time. We have not dictated the means by which public utilities are to make this information simultaneously available to all.

This same concern for the unequal distribution of market information, in a manner that may benefit select recipients with commercial or competitive information that is not equally available to others, leads us, after a review of the comments, to extend the standards of conduct to cover any market information gathered by Transmission Providers in the course of responding to transmission or ancillary service inquiries.

Our concern, based in part on our experience with implementing and monitoring electronic bulletin boards developed for use by the natural gas pipeline industry, is that there remains the incentive for a Transmission Provider to share with its own merchant employees, or those of an affiliate, any information it has developed (not limited to transmission system information) in responding to requests made over the OASIS. This is particularly a concern with respect to market information developed in the course of denying a request for transmission service.

While we have developed procedures dealing with the obligations of Transmission Providers in responding to requests for service, we believe that these procedures, alone, may not be sufficient to eliminate the possibility of an unfair competitive advantage to employees of the Transmission Provider

[33] *See, e.g.*, Illinova Power Marketing, Inc., 74 FERC ¶ 61,313, *slip op*. at 4–6 (1996); USGen Power Services, L.P., 73 FERC ¶ 61,302 at 61,845 (1995).

(or an affiliate) engaged in merchant functions, by virtue of access to market information not shared with others.

Accordingly, we will add to the standards of conduct a provision that precludes a Transmission Provider from sharing market information acquired from nonaffiliated Transmission Customers or potential nonaffiliated Transmission Customers or developed in the course of responding to requests for transmission or ancillary service. In this manner, we can be better assured that employees of the Transmission Provider or an affiliate engaged in merchant operations do not develop a competitive advantage by virtue of operation of an OASIS. The Transmission Provider may only reveal information about transmission requests as provided in the provisions of this rule (section 37.6 (e)) dealing, generally, with responses to transmission and ancillary service requests and, specifically, with transaction confidentiality (except to the limited extent that this information is required to be posted on the OASIS).

3. Whether To Require the Separation of Generation and Transmission Functions

In the RIN NOPR we proposed standards of conduct that would require Transmission Providers and their affiliates to separate system operation and reliability functions from wholesale merchant functions. Both transmission and generation functions are included within system operation and reliability functions. The RIN NOPR, notwithstanding Questions 42 and 43, did not propose that these functions (transmission and generation) be separated. Nor did we propose that Transmission Providers divest their ownership of generation assets.

We received numerous comments in response to our questions 42 and 43 that asked whether, if the Commission would go beyond unbundling transmission and generation merchant functions to order the unbundling of generation and transmission operations, this would necessitate revision of the proposed standards of conduct and whether this would adversely affect reliability.[34] After reviewing the comments, we conclude that we should require—with these final rules—only the unbundling of the transmission operations and wholesale marketing functions of public utilities and their affiliates, as proposed in the RIN NOPR. We do not extend these rules to require the unbundling of transmission and generation control functions or to mandate the divestiture by Transmission Providers of their generation assets.

We will require the functional unbundling of transmission operations and wholesale marketing functions because we are persuaded that this will prevent abuses based on preferential access to information and other discriminatory behavior, without compromising system reliability. The standards of conduct are designed to accomplish this: (a) By requiring that transmission-related information be made available to all customers (including employees of the public utility, and any affiliate, engaged in merchant functions) through OASIS postings available to all customers at the same time and on an equal basis; and (b) by prohibiting the employees of Transmission Providers and any affiliates from disclosing (or obtaining) non-public transmission-related information, through communications not posted on the OASIS.

G. Section 37.5—Obligations of Transmission Providers

This section of the final rule adopts, without substantive change, the provisions proposed as section 37.4 (Standardization of Data Sets and Communication Protocols) and section 37.5 (Obligations of Transmission Providers) in the RIN NOPR. The final rule requires, in paragraph (a), that a Transmission Provider must provide for the operation of an OASIS either individually or jointly with other Transmission Providers and it must do so in accord with the requirements of Part 37. Paragraph (b)(1) requires that the OASIS must give access to relevant standardized information pertaining to the status of the transmission system as well as to the types and prices of services. Finally, in paragraph (b)(2), the rule requires that the OASIS must be operated in compliance with the protocols set out in the publication, *OASIS Standards and Communication Protocols.*

In the RIN NOPR, we explained that each Transmission Provider would be responsible for compliance, regardless of whether it establishes its own OASIS or participates in a joint OASIS.[35] The final rule does not change this. In a related provision, we proposed, in § 37.1, that Part 37 would apply to any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce. However, as noted by many commenters, it is quite probable that individual public utilities may turn the operation of their transmission system and information system over to an ISO or other joint or regional entity. (This has been provided for in the definition of the term ''Responsible Party''). This raises the issue of the Commission's jurisdiction over such entities.

Under section 201(e) of the FPA, a ''public utility'' means,

> Any person who owns or operates facilities subject to the jurisdiction of the Commission under this Part (other than facilities subject to such jurisdiction solely by reason of section 210, 211, or 212).[36]

To the extent that anyone is given control and decision making authority over the transmission operations of a public utility's transmission facilities, it clearly would ''operate'' public facilities, within the meaning of section 201(e), and therefore would be subject to the Commission's jurisdiction.[37] To the extent that a public utility turns over its operations to an ISO or any other joint entity to satisfy the Open Access and OASIS requirements, the ISO or any other entity would fall within the definition of a ''public utility'' under § 201 of the FPA and thus would be subject to the OASIS regulations of Part 37.

H. Section 37.6—Information To Be Posted on an Oasis

In the RIN NOPR, we proposed, in sections 37.7 through 37.14, rules governing: (1) The information that must be posted on an OASIS; (2) the procedures for the posting and updating of information on the OASIS; (3) the posting of discounts; (4) procedures for Transmission Providers to respond to customer requests for transmission service; (5) procedures for communicating denials of requests for service and curtailments; and (6) the posting of information about scheduling and affiliate transactions. These

[34] The commenters nearly universally focused their presentations on why the Commission should not order an unbundling of generation and transmission operations, rather than addressing the precise topic we set out. In any event, the issue is now moot, as we have decided not to order Transmission Providers to separate their generation and transmission operations at this time. If, however, with experience we discover that the steps we are ordering here are not adequate to remedy undue discrimination, we can revisit this issue.

[35] NRECA commented that the Commission should ensure that expenses by a joint OASIS are subject to the Commission's jurisdiction and audit authority. We agree. We will treat this as a normal ratemaking expense issue and will allocate such costs on a case-by-case basis when such expenses are presented to us for our review.

[36] 16 U.S.C. § 824.

[37] *See, e.g.,* Bechtel Power Corporation, *order granting declaratory order and disclaiming jurisdiction,* 60 FERC ¶ 61,156 at 61,572 (1992) (on control issue), and FPC v. Florida Power & Light Company, 404 U.S. 453 (1972) (on defining jurisdictional facilities).

provisions have been consolidated and are now covered in § 37.6 of the regulations adopted by this final rule.

As discussed in more detail below, section 37.6 has eight paragraphs. Paragraph (a) lists the objectives of an OASIS. Paragraph (b) lists what must be posted for public transmission capability—that is, available transmission capability (ATC) and total transmission capability (TTC)—as well as how and when this information is to be updated. Paragraph (c) sets out the requirements for posting transmission service products, including resold capacity as well as their prices. Paragraph (d) provides the same for offerings of ancillary services. Paragraph (e) sets out the requirements for posting transmission service requests and responses including service denials and curtailment or interruption of transmission. Paragraph (f) provides requirements for posting transmission service schedules. Paragraph (g) deals with posting other transmission-related communications. Finally, paragraph (h) sets out the requirements for auditing information.

Some of the proposed provisions have not been adopted. These include requirements concerning an application procedure for requesting transmission service (§ 37.9(b)(5) of the proposed regulations); requirements imposed on the reseller to notify the Transmission Provider of certain information (§ 37.9(c)(3) of the proposed regulations); and the steps that must be followed by the Transmission Provider and Requester in their negotiations (§ 37.12 of the proposed regulations). These did not prescribe information that must be posted; rather, they were concerned with how parties should conduct business in an open access environment. These matters are considered in the Open Access Final Rule.

1. OASIS Objectives (§ 37.6(a))

The Commission proposed five objectives for the OASIS in the RIN NOPR.[38] Few comments were received on these objectives; none were substantive. Thus, we adopt these objectives without substantive revision in the final rule.

2. Posting Transmission Capability (§ 37.6(b))

a. ATC for Network Integration Service. The RIN NOPR discussed requiring the posting of available transmission capability for network service. As we acknowledged in the RIN NOPR,[39] before-the-fact measurement of the availability of network transmission service is difficult. Nonetheless, it is important to give potential network customers under the Commission's *pro forma* tariff (as discussed in the Open Access Final Rule)[40] an easy-to-understand indicator of service availability. To this end, the Commission requested comments on how best to post the availability of network transmission service on the OASIS (Question 3).

NERC reiterated the statement in the What Group report that ''it does not seem possible to post the availability of Network Integration Transmission Service'' on an OASIS. No other commenter disagreed.

NERC went on to describe some of the challenges involved with calculating available transmission capability (ATC) for network integration service. Network service is a complex, long-term relationship between a requester and provider that must be investigated in detail because it involves the specification of multiple points of receipt or delivery or both. Because of the long-term nature of network service, the planning process involves a complex interrelationship of future loads and resources, with an impact on the network that is extremely location dependent. A major difficulty in estimating network ATC is the lack of specific locations for which to calculate an impact on the network. Each network service request would be unique, with different sets of integrated loads and generating stations affecting the network, including its constrained paths, differently.

The Commission also asked if there were any alternative service that is more suitable to measurement than the current version of network service. Some commenters said that it might be possible to devise a concept which supports better measurement of network-like service availability, but devising and implementing such a new concept within the proposed initial implementation time line for OASIS is not feasible. The Commission is not, at this time, persuaded to require the posting of ATC for network service.

b. Minimizing the Reporting of ATC (§§ 37.6(b) (1) and (3)). In the RIN NOPR, the Commission requested comments on ways to minimize the burden of ATC calculations, while ensuring that wholesale Transmission Customers have the information they need (Question 5).

Commenters suggested a number of ways to minimize the reporting of ATC, including less frequent updates, developing standardized methods for calculating ATC, and encouraging regional efforts. Most of the comments discussed ways to limit the number of paths for which ATC has to be posted.

The What Group proposed that ATC be posted only for paths as ''business needs'' arise. This proposal was intended to limit the number of paths for which ATC must be posted. A ''business need'' was defined, in part, by a Transmission Customer requesting information about a path. A number of commenters supported the proposal to limit paths based on ''business need.''[41]

The Commission suggested in the RIN NOPR a different approach to the problem. Calculating ATC and updating frequency could be based, instead, on the level of activity and constraints on a given path. This approach was supported by a number of commenters.[42] A number of commenters wanted to leave to the Transmission Provider the decision of which paths to post ATC.[43]

Detroit Edison, Oklahoma G&E and PSNM suggested that customers could also identify paths, along with a process for deleting them. NEPOOL and Detroit Edison stated that they will post ATC for all control area interfaces and any internal constraints. The Western Group had a similar proposal.

NE Public Power District, NERC and NSP commented that ATCs should be posted only for constrained paths. PJM and WP&L proposed that, for unconstrained paths, static numbers or limits could be used and would be updated infrequently. VEPCO suggested that paths be coded by the quality of the ATC calculation used and that high quality effort be used only when ATC is less than 25 percent of the total transmission capability. ConEd suggested that posting could be sorted by frequency of update so that busier paths would be at the top of the list.

Dayton P&L suggested mandatory information on ATC be limited to: (1) Identification of the interface; (2) firm and non-firm ATC (hourly for the current day, daily for the next seven

[38] *See* RIN NOPR text at section III.C (60 FR at 66188) and the proposed regulation at 18 CFR 37.7 (60 FR 66200).

[39] *See* RIN NOPR text at section III.C (60 FR at 66188).

[40] *See* Open Access Final Rule at sections IV.G and IV.H.

[41] *See, e.g.,* Arizona, ConEd, NEPOOL, NE Public Power District, NERC and Western Group comments.

[42] *See* Basin EC, Duke, NE Public Power District, Tallahassee, Union Electric, and VEPCO comments. Only Arizona said it was a bad idea because it would be too subjective and confusing.

[43] *See* Central Illinois Public Service, Detroit Edison, Omaha PPD, PSNM, Texas Utilities, Union Electric, and VEPCO comments.

days, weekly for the next four weeks, monthly for the next 12 months); and (3) price for each service.

MAPP summarized the issue well when it stated ''[t]he burden of ATC calculations will be determined by the number of paths for which ATC is being calculated and posted, the accuracy needed and the frequency of required update.''

The proposed regulations have been modified to implement the alternative approach suggested by the Commission in the RIN NOPR. The regulations in § 37.6(b)(1) define the paths for which ATC and TTC must be posted. These are called ''posted paths.''

A transmission path becomes a ''posted path'' in one of three ways. First, ATC and TTC must be posted for any path between two control areas. Second, posting is required for any path for which transmission service has been denied, curtailed or subject to interruption during any hour or part of an hour for a total of 24 hours in the last 12 months. In counting up to 24, curtailment for any part of an hour counts for a whole hour. Finally, Transmission Customers can request that ATC and TTC be posted for any other transmission path. Customer requested postings may be dropped if no customer has taken service on the path in the last 180 days.

The regulations in § 37.6(b)(3) define two classes of posted paths based on usage: ''unconstrained'' and ''constrained''. A constrained posted path is one for which ATC has been less than or equal to 25 percent of TTC for at least one of the last 168 hours or is calculated to be 25 percent or less of its associated posted TTC during the next 7 days. An unconstrained posted path is any posted path that is not a constrained posted path.

For constrained posted paths, ATC and TTC for firm and non-firm service would have to be posted for the next 168 hours and, thereafter, to the end of a 30-day period. In addition, ATC and TTC for firm and non-firm service must be posted for the current month and the next twelve months. However, this monthly posting for ATC and TTC for non-firm service is required only if requested by a customer. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC and TTC will be posted daily for each period. A posting for a constrained posted path must be updated when transmission service on the path is reserved or service ends or when the path's TTC changes by more than 10 percent.

For an unconstrained posted path, ATC and TTC for firm transmission service and non-firm transmission service would be required to be posted for the next seven days and for the current month and the next twelve months.[44] If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC and TTC will be posted for the current day and the next six days following for each period. Postings for an unconstrained posted path must be updated when the ATC changes by more than 20 percent of the path's TTC.

We will not require ATC and TTC to be posted on the OASIS more than thirteen months in advance, with the following exception. If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following to the end of the planning horizon, but not to exceed 10 years.

c. Methodology for Calculating ATC and TTC (§ 37.6(b)(2)). In the RIN NOPR, the Commission discussed the requirements for calculating ATC and TTC.[45] Recognizing that formal methods do not currently exist to calculate ATC and TTC, the Commission requested comment on how to develop a consistent, industry-wide method of calculation (Question 4).

Most commenters recommended that the Commission defer to NERC regarding the development of a consistent, industry-wide method of calculation. NERC, in turn, recommended that the Commission give deference to NERC's ongoing, industry-wide effort. NERC's Transmission Transfer Capability Task Force (TTC Task Force), with an expanded roster to include representation from all segments of the electric industry, was formed to develop uniform definitions for determining ATC and related terms. Because the TTC Task Force will not be finished with its assignment until May 1996, NERC recommended that the OASIS final rule not contain specific definitions of terms such as ATC, but instead be limited to a general framework within which the same information can be made available to all transmission users at the same time.

The Commission encourages industry efforts to develop consistent methods for calculating ATC and TTC. Consequently, the final rule follows the proposed regulations in requiring that ATC and TTC be calculated based on a methodology described in the Transmission Provider's tariff and that it be ''based on current industry practices, standards and criteria.'' (Section 37.6(b)(2)(i)).[46]

As provided in the *pro forma* tariff, Transmission Providers may themselves purchase only transmission capability that is posted as available. This requirement should create an adequate incentive for them to calculate ATC and TTC as accurately and as uniformly as possible.

d. Accommodating Flow-Based Pricing. In the RIN NOPR, the Commission asked for comment on what requirements would have to be changed if the electric power industry moves to regional pricing, flow-based pricing, or other pricing models that depart from the ''contract path'' approach (Question 2).[47]

Many commenters expressed the need for OASIS flexibility to support both contract path and actual flow models.[48] Com Ed stated that, so long as the OASIS is flexible, appropriate postings involving ATC, price, and related information will develop for use with tariffs using flow-based pricing.

The Commission concludes that the proposed regulations were general enough to accommodate flow-based pricing methods. Therefore, we have provided no special provision regarding flow-based pricing in the final rule. Any OASIS-related issue that arises when flow-based proposals are made can be dealt with at that time. We cannot accurately foresee what issues may arise concerning flow-based pricing because this is an evolving area.

e. Actual Flow Data. The RIN NOPR proposed the posting of actual path flow data to better inform Transmission Customers about the true network impacts of taking service on a contract path basis.[49] The Commission asked whether there are any difficulties, technical or otherwise, associated with posting actual path flows (Question 20).

In response, commenters stated that such posting is technically difficult, but possible. However, they question the value and usefulness of such postings.[50]

[44] The terms ''firm point-to-point transmission service'' and ''non-firm point-to-point transmission service'' are defined in the definition section of the *pro forma* tariff for point-to-point service.

[45] *See* RIN NOPR text at section III.C (60 FR at 66188) and the proposed regulation at 18 CFR 37.9(b)(2) (60 FR 66200).

[46] The *pro forma* tariff in the Open Access Final Rule provides that Transmission Providers must develop a method for calculating ATC and TTC and must include a description of this methodology in their tariffs.

[47] *See* RIN NOPR text at section III.C (60 FR at 66186).

[48] *See, e.g.,* Consumers Power, Basin EC, ERCOT, NEPOOL, PA Com, How Group, NIEP, NYPP, NERC, Ohio Com, OK Com, Oklahoma G&E, PSNM, Texas Utilities, Western Group, PacifiCorp, and PJM comments.

[49] *See* RIN NOPR text at section III.C (60 FR at 66191).

[50] *See, e.g.,* Allegheny, Arizona, Central Illinois Public Service, Carolina P&L, Florida Power Corp,

Commenters stated that information on actual path flows is voluminous, excessive, and burdensome to post.

Allegheny stated that actual flow information could be commercially sensitive depending on the degree to which a generator's output can be determined from it. Oklahoma G&E stated that actual flows are meaningless unless accompanied by voltage, line thermal limits, and line first contingency incremental transfer capability. NERC commented that actual path flow postings would be irrelevant or even misleading to the Transmission Customer and should not be required. NERC added, however, that the Commission should not preclude such postings either. The How Group pointed out that, from a technical standpoint, posting actual path flows significantly increases the level of detail in information about transmission service. APPA answered that some regions already have the capability to post actual flows, but functional separation diminished the need for the Commission to require the posting of actual flows.

The final rule does not require the posting of actual path flows. As long as ATC and TTC are calculated to reflect network conditions, including parallel path constraints, actual flow data need not be posted. The Commission may reassess this issue after reviewing the proposals of the TTC Task Force on methods for calculating ATC and TTC expected in May 1996.

f. Providing Supporting Information (§ 37.6(b)(2)(ii)). In the RIN NOPR, we proposed that public utilities must post all data used in calculating the ATC and TTC and make such data publicly available.[51] The Commission received a number of comments on this proposal.

A majority of commenters stated that supporting data should not be available on the OASIS.[52] About half of the commenters argued that the data should be available off-line.[53] Others suggested that procedures and software used in calculating ATC and TTC must be posted.[54] NYPP suggested that a bibliography of supporting information should be maintained on the OASIS.

Having this information available is essential for building and maintaining trust in the information posted on the OASIS. Transmission Providers generally seem willing to provide this information after-the-fact and off-line. Since this information would be used only after-the-fact and can be voluminous, the final regulations require that ATC and TTC supporting information be made available by the Responsible Party within one week of posting, on request, in their original electronic format and at the cost of reproducing the materials. A requirement specifying how long the information must be retained also has been added.

g. Long-Term Studies (§ 37.6(b)(2)(iii)). The RIN NOPR proposed that any planning or specifically requested studies of the transmission network performed by the Transmission Provider be posted on a same-time basis.[55] This would include only those parts of customer-specific interconnection studies that relate to network impacts.

The majority of commenters responded that transmission planning studies should not be posted on the OASIS. ConEd and MAPP suggested an index to be maintained on the OASIS. NEPOOL, Tallahassee, and Montana Power suggested that summaries should be maintained on the OASIS.

As with the ATC supporting information, having this information available is essential for building and maintaining trust in the ATC and TTC posted on the OASIS. Since this information would be used only after-the-fact and can be voluminous, the final regulations require that final transmission studies be available from the Responsible Party on request in original electronic format and at the cost of reproducing the materials. A list of available studies is to be posted on the OASIS. A requirement specifying how long the studies must be retained also has been added.

3. Posting Transmission Service Products and Prices (§ 37.6(c))

Paragraph 37.6(c) of the regulations adopts several of the proposed provisions. It requires Transmission Providers to post prices and a summary of the terms and conditions of transmission products. In addition, Transmission Providers must provide a downloadable file of their complete tariffs. Furthermore, customers who use an OASIS to resell transmission capacity must submit relevant information about their resale transactions to the Transmission Provider for posting to the same OASIS as used by the Transmission Provider in originally offering that capacity. As proposed in the RIN NOPR, the Transmission Provider must post this information about resales on the same display page, using the same tables, as similar capacity being sold by it. Similarly, the information must be contained in the same downloadable files as the Transmission Provider's own available capacity. A customer who does not use an OASIS to arrange a resale of transmission capacity must, nevertheless, inform the original Transmission Provider of the transaction within the time limits prescribed by the ''Sale or Assignment of Transmission Service'' section of the *pro forma* tariff.

The proposed standards of conduct required a Transmission Provider that offers any discount on behalf of its power customers or those of an affiliate, to post offers for similar service containing comparable discounts, at the same time, to all Transmission Customers.

As to discounts that the Transmission Provider has agreed to give to any Transmission Customer (affiliated or unaffiliated), the Commission proposed requiring that these discounts be posted within 24 hours after the agreement is entered (measured from when ATC is adjusted in response to the agreement), and that they remain posted for 30 days. The Commission sought comment on whether all transmission discounts should be posted on the OASIS, or only those provided to the Transmission Provider or its affiliates (Question 14).

Most commenters, including representatives with diverse interests such as APPA, EEI, Continental Power Exchange, EGA, EEI, NIEP, and NRECA, argued that discounts must be made available to all customers. NRECA especially, was concerned about the potential for selective discounting. The Ohio Com, clearly concerned about allowing Transmission Providers to negotiate privately, asked that we clarify how discounting would work, and EGA raised some practical concerns about how the Commission's proposal would work. EGA asked whether, when a discount is offered to an affiliate, discounts must be offered to others on the same path, all paths, or only paths needed to get to the buyer to whom the affiliate is selling. This issue is addressed in the Open Access Final Rule, which concludes that such

Montana Power, NERC, Omaha PPD, Texas Utilities, Union Electric, and VEPCO comments.

[51] *See* RIN NOPR text at section III.C (60 FR at 66190) and the proposed regulation at 18 CFR 37.9(b)(6) (60 FR 66200).

[52] *See, e.g.,* Allegheny, Central Illinois Public Service, Continental Power Exchange, EPRI, Florida Power Corp, MAPP, NERC, NE Public Power District, NYPP, Ohio Edison, PSNM, VEPCO, Western Group, and WP&L comments.

[53] *See, e.g.,* Allegheny, ConEd, Detroit Edison, Duke, EPRI, Idaho, MAPP, NEPOOL, NE Public Power District, Ohio Edison, PSNM, VEPCO, and Western Group comments.

[54] *See, e.g.,* Duke, EPRI, Idaho, PSNM, Western Group comments.

[55] *See* RIN NOPR text at section III.C (60 FR at 66191) and the proposed regulation at 18 CFR 37.8(c) (60 FR 66200).

discounts must be offered to all customers on all unconstrained paths.

Several commenters were against discounting, but would accept discounts if they were made available to all customers.[56] Several commenters agreed with the proposal to require posting of discounts offered to affiliates and delaying the reporting of discounts to others.[57] However, CCEM wants to change the 24-hour delay period to 30 days.

SCE&G and Union Electric would allow discounting but not post them on the OASIS. Central Hudson would post only affiliate discounts. SMUD argued that selective discounting is good and stated that, if public utilities must offer discounts to everyone, no discounts would be offered to anyone.

The question of whether discounts may be offered is discussed in the Open Access Final Rule.[58] If a Transmission Provider offers a discount for transmission service to its own power customers or those of an affiliate, it must, at the same time, post on the OASIS an offer to provide the same discount to all eligible customers on the same path and on all unconstrained transmission paths. As to discounts for ancillary services, if a Transmission Provider offers a rate discount to an affiliate, or attributes a discounted ancillary service rate to its own transactions, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all eligible customers. If a Transmission Provider offers discounts to non-affiliates, it must offer to do so on a basis that is not unduly discriminatory. Any discounts under § 37.6(c)(3) offered to affiliates or to the Transmission Provider's own power customers must be posted on the OASIS when they are offered pursuant to § 37.4(b)(5)(v). Discounts offered to non-affiliates must be posted within 24 hours of when ATC is adjusted in response to the transaction.

4. Posting Ancillary Service Offerings and Prices (§ 37.6(d))

Transmission Providers are required to post on the OASIS information about all ancillary services required by the Open Access Final Rule to be provided or offered to customers.[59] A Transmission Provider may, at its discretion, post information on the OASIS about other interconnected operation services, offered by itself or third parties, that are not services required by the Open Access Final Rule to be offered to customers. However, if a Transmission Provider elects to post these optional services for any party, including itself, then it must post on its OASIS, for a reasonable cost based fee, the same type of information about comparable optional ancillary services offered by third parties.

In the RIN NOPR, we proposed the posting of price and other information about ancillary services.[60] We requested comment on: (1) The information needed about ancillary services (Question 12); (2) how often the information should be updated (Question 13); and (3) where on the information network offers of ancillary services by entities other than the Transmission Provider should be placed (Question 9).

While there is near consensus among commenters on the need to update ancillary services information as it changes, there is widespread disagreement on what information about ancillary services should be posted and where on the OASIS offers by other entities to provide ancillary services should be placed. Some commenters request that the Commission allow flexibility because the information requirement may depend upon the industry structure that develops in response to the Open Access Final Rule. NERC asserted that it is impractical to expect the initial OASIS to be the vehicle for posting information on the availability and price of all ancillary services.

Ancillary service providers are required to post all pertinent information about their ancillary service offerings (*e.g.*, a description of the service being offered, its availability, and its price) so that Transmission Customers may compare offers and decide which offer best suits their needs. Information about ancillary services should be updated as it changes. Postings by customers and third parties should be on the same page, and in the same format, as postings of the Transmission Provider.

5. Posting Transmission Service Requests and Responses (§ 37.6(e))

Section 37.6(e) requires that all requests by customers for transmission service that the Transmission Provider offers under the *pro forma* tariff must be made on the OASIS. The Responsible Party is required to provide to others on the OASIS the essential information relating to such requests, with the identity of the parties masked, if requested. Additionally, the section sets out the steps that must be followed in processing such requests, including the posting of curtailments, interruptions, or denials of service.[61] The final OASIS regulations require that a record of transactions not resulting in agreements also be kept for audit purposes. We now discuss some special issues arising under this provision and the comments relating to those provisions.

a. Posting Curtailments and Interruptions (§ 37.6(e)(3)). We proposed requiring that, when a transaction is curtailed, a Transmission Provider must post the reason that the transaction was curtailed and the available options, if any, for adjusting the operation of the Transmission Provider's system to increase transfer capability in order to accommodate the transaction.[62] Since scheduling and the curtailment of schedules would not be done through the information network initially, this curtailment data would be for information purposes only.

The Commission requested comments on what information about curtailments should be communicated on an OASIS (Question 7). Only Union Electric, among the commenters who answered this question, argued against posting information about curtailments or recording this information in an audit file. Among those who supported posting or recording, the differences were in how much information should be provided, where the information should be placed, and who should have access to the information.

The comments expressed support for a Transmission Provider setting out in its tariff, or elsewhere, curtailment or interruption rules or constraint relief protocols.[63] This would let a customer know what to expect when there is a constraint and would allow the Transmission Provider to be held to a formal set of procedures. Then, when a curtailment occurs, postings on the OASIS can refer to steps and reasons defined in the curtailment procedures.

Many commenters agreed that at least some basic information about curtailments needs to be posted or documented in the audit file. Several commenters pointed out that there may

[56] *See* ERCOT, MidAmerican, NUCOR, and Public Generating Pool comments.

[57] *See* CCEM, OK Com, and Tallahassee comments.

[58] *See generally* Open Access Final Rule at sections IV.D and IV.G.

[59] *See generally* Open Access Final Rule at section IV.D.

[60] *See* RIN NOPR text at section III.C (60 FR at 66190).

[61] The Open Access Final Rule discusses curtailments at section IV.G and provides that a company's curtailment policy is to be described in its tariff.

[62] ''Curtailments'' are service cutbacks made for system reliability reasons and are distinguishable from ''interruptions'', which are made pursuant to tariff conditions.

[63] *See* APS, NERC, and NIEP comments.

be some lag before these postings are placed on the OASIS because control room personnel may need time to determine and resolve the problem.[64] Some commenters believed that these postings should be made available only to those curtailed.[65]

The proposed regulations addressed curtailments and denials of service together. In this final rule, denials are distinguished from curtailments of service. Transmission Providers are not required to offer options for making capacity available to those curtailed, but if options are offered, they must be offered to curtailed and interrupted customers at the same time.

As discussed in the Open Access Final Rule, transmission tariffs must include rules for curtailment and interruption of service, including clear steps or stages in the process for relieving constraints, and transmission service agreements must clearly identify the service's priority relative to concurrent services. Consistent with these requirements, the final rule here provides that, when curtailments or interruptions take place, they must be posted as soon as possible and must include identification of the service (with the identity of the customer masked), the reason for the curtailment or interruption, and the tariff-defined step in the curtailment and interruption process. In the event that an emergency situation affecting system reliability delays this posting, the posting must be made as soon as practicable thereafter along with an explanation for the delayed posting.

Curtailments and interruptions will be recorded for audit purposes. This audit data should contain enough information about the timing of superseding requests and changes in ATC to document the reason for a curtailment or interruption. The final rule also provides that customers have the right to request an explanation of the reason for a curtailment or interruption.

b. Posting Denials of Requests for Service (§ 37.6(e)(2)). In the RIN NOPR, we proposed requiring that, when requests for service are denied, Transmission Providers must communicate to Transmission Customers through the OASIS: the reason(s) that the transaction(s) could not be accommodated; and the available options, if any, for adjusting the operation of the Transmission Provider's system to increase transfer capability to accommodate the transaction(s). The Commission requested comments on what information about denials of requests for service should be communicated on an OASIS (Question 7).

As with curtailments, only Union Electric out of the commenters who answered this question opposed posting information about denials of service on the OASIS or recording this information in an audit file. Many commenters agreed that at least some basic information about denials should be posted. Some commenters believed that these postings should be available only to those denied service.[66]

Service can be denied for two basic reasons: either (1) the customer requested more than the posted ATC or (2) after the request for service was made, conditions changed due to preexisting requests or unforeseen events reducing capacity. Denials should be handled as part of the request and response process. A requester should receive a standardized reason for denial as part of the response. Denials would not be posted. Instead, denials must be recorded for audit purposes and maintained as provided in section 37.7(b). This data should contain the information about a denial needed to explain the reason for a denial. Under the final rules, customers have the right to request an explanation of the standardized reason for a denial.

c. Transaction Anonymity (§ 37.6(e)(3)(i)). In the RIN NOPR, we proposed that, generally, information concerning negotiations on transmission requests need not be posted unless an agreement to provide the transmission is reached.[67] This information would be available only after-the-fact in the audit file. In addition, if an agreement is reached, the identity of parties to transmission transactions would be masked until 30 days after the date when the Transmission Provider's ATC was adjusted in response to the transaction. (This might be after the date when service begins). After that date, all transaction data would be made available. In addition, we proposed that transmission transaction prices be included in the information in the audit file. Price information concerning cost-based transmission services would not be considered commercially sensitive.

The Commission requested comment on what information should be considered commercially sensitive, the 30-day release period proposal, and on how and when commercially sensitive information should be released to concerned parties before the standard release period and whether affiliated transactions should be treated differently (Question 24).

Several commenters agreed that information about negotiations that do not reach agreement should not be reported.[68] No commenter argued for making this information public.

A number of commenters supported the 30-day delay on providing commercially sensitive information.[69] Several, however, thought the information should be provided as soon as possible.[70] Others thought it should be provided quarterly.[71] WP&L proposed a 60-day delay. Dayton P&L said that the delay should depend on contract length. Union Electric suggested a delay of 30 days after the transaction begins and not after the ATC is adjusted.

Commenters split on the question of whether price data are commercially sensitive.[72] Commenters listed several items as commercially sensitive that were proposed to be posted. These are ATC supporting information,[73] transmission schedule information,[74] generation run status,[75] amount provided,[76] terms and conditions,[77] and duration.[78]

NE Public Power District argued for full disclosure of all but generator information because, as a public entity, it must disclose such information. NIEP stated that comparability should be the ruling principle in information disclosure.

The final rule adopts the NOPR proposal and provides that the identity of parties to an agreement are confidential during ongoing negotiations and for 30 days from the time ATC is adjusted. Although not explicitly required in the new Part 37, the price of services offered on and

[64] *See* Allegheny, Com Ed, CSW, NERC, NRECA, and SCE&G comments.

[65] *See, e.g.,* Allegheny and Central Illinois Public Service comments.

[66] *See* Allegheny and Central Illinois Public Service comments.

[67] *See* RIN NOPR text at section III.C (60 FR at 66191) and the proposed regulation at 18 CFR 37.14(d) (60 FR 66201).

[68] *See, e.g.,* Allegheny, Detroit Edison, El Paso, NorAm, and OK Com comments.

[69] *See* Allegheny, CCEM, El Paso, Oklahoma G&E, PJM, PSNM, and Western Group comments.

[70] *See* APPA, Continental Power Exchange, MidAmerican Energy, and NIEP comments.

[71] *See* Arizona, ConEd, and NorAm comments.

[72] EGA, NUCOR, NRECA, Omaha PPD, and PJM supported the proposition that the data are not commercially sensitive. Arizona, Central Illinois Public Service, Detroit Edison, OK Com, PSNM, Seattle, and Western Group argued that the data are commercially sensitive.

[73] *See* Carolina P&L and El Paso comments.

[74] *See* Central Illinois Public Service and OK Com comments.

[75] *See* Allegheny, Carolina P&L, CSW, Detroit Edison, EGA, NE Public Power District, and PJM comments.

[76] *See, e.g.,* Allegheny and WP&L comments.

[77] *See* Central Illinois Public Service comments.

[78] *See* Allegheny comments.

agreed to through the OASIS are not considered commercially sensitive.[79]

6. Posting Facility Status Information

The RIN NOPR discussed the fact that the ATC of some transmission paths depends on generator run status or megawatt output, or both, as well as on other system elements.[80] We proposed requiring Transmission Providers to post information about those system elements that have a direct and significant impact on ATC. Such elements could include generators, transmission lines, phase shifters, series and shunt capacitors, static VAR compensators, special protection systems or remedial action schemes. We, therefore, requested comment on whether it is sufficient to provide information only about planned outages and (for both planned and forced outages) return dates for system elements deemed to have a direct and significant impact on ATC and whether posting this information would cause any confidentiality concerns (Question 18). We also requested comment on how ''significant and direct impact'' should be defined (Question 19).

Additionally, we requested comment on whether it would be sufficient to post the changes to ATC corresponding to the planned outage or return dates of generators (Question 21); and whether, if operating guides, nomograms, operating studies, and similar information were posted, the run status of those generators with a significant and direct impact on ATC could be deduced (Question 22).

Comments

A number of commenters stated that the posting of facility status information should not be a requirement.[81] These commenters reasoned that the posted ATC and TTC values would reflect facility status impacts and that posting status information therefore would be unnecessary and burdensome, and would render the information network unmanageable. With regard to generator status and outage information, a number of respondents argued that generator status and outage-related information is commercially sensitive and confidential.[82] They stated that posting generator-related information would give an unfair advantage to competitors. Some opposing the posting of generation-related information also added that the Commission's proposed standards of conduct would make it unnecessary to post this information because the Transmission Customer's and the Transmission Provider's wholesale marketing functions would rely on the same information.[83] A number of Transmission Providers believed that facility status data can be archived and made available for after-the-fact audits.[84]

A second group of commenters believed that facility status information should be posted on the OASIS.[85] With regard to generator status and outage data, Seattle responded that planned generator outage data should be updated as it changes and that an explanation of the impact of typical outage configurations should be made available to all transmission users in advance. APPA stated that the run status (on-line or off-line) of any generating unit should not be kept confidential. APPA argued that keeping such information confidential, under the guise of competitive necessity, is an excuse to protect opportunities to game the market. NCEMC stated that, because the transmission user needs to be able to do a reliability and risk assessment of various available power supply sources and transmission paths, it probably is not sufficient to post ATC changes corresponding to generation outages.

A third group of commenters suggested that, while generator status-related information should not be posted, information about transmission facilities with direct and significant impact on ATC and TTC could be posted.[86] There were diverging views among the commenters as to whether posted ATC or TTC values would reveal the run status of generators if operating guides, nomograms, operating studies, and similar information were posted. A number of commenters responded that ATC and TTC are affected by many variables and, even though in some cases it may be possible to deduce the run status of certain generators from the posted ATC or TTC, these deductions would be uncertain.[87]

NERC responded that it may be possible, over time, to recognize patterns and supporting data that would indicate which generator went off-line, but not whether the reason is a planned outage, forced outage, reserve shutdown, or other reasons. NERC explained that a run status so deduced would itself be an estimate and not as commercially sensitive as knowing the reason for that status. Florida Power Corp and Montana Power responded that customers will be able to deduce generation-related information from changes in ATC if guides, nomograms, or studies are posted and, therefore, such information should not be posted.

By contrast, a number of commenters stated that nomograms, derating tables, and operating studies can be used to identify equipment that has a direct and significant impact on ATC and TTC.[88] The Western Group responded that, where study results have been summarized in nomograms, derating tables, and operating guidelines and procedures, these summary forms should be made available as information on the OASIS.

A number of respondents answered that it is not necessary to define ''significant and direct impact'' because ATC and TTC are the only quantities that need to be posted.[89] ConEd stated that the definition of ''significant'' should be consistent with local and regional procedures. Duke and Florida Power Corp commented that the Commission should work through NERC in developing appropriate definitions. NYPP, on the other hand, stated that ''significant and direct impact'' can be determined only on a case-by-case basis. Montana Power defined the term as a reduction of ATC that results in the denial of service. Continental Power Exchange proposed that any system element affecting ATC more than 10 percent should be considered significant. CSW proposed a 50 percent threshold. CSW further proposed to include those elements that can cause a reduction of more than 25 percent of the normal flows across an interface.

[79] We note, in this regard, that § 205(c) of the FPA requires public utilities to have their prices on file with the Commission and available for public inspection.

[80] *See* RIN NOPR text at section III.C (60 FR at 66191).

[81] *See* Allegheny, Central Illinois Public Service, Com Ed, CSW, Dayton P&L, Detroit Edison, Duke, Montana Power, NERC, NYPP, Ohio Edison, PJM, PSNM, Texas Utilities, VEPCO, and WP&L comments.

[82] *See* Allegheny, Arizona, Central Illinois Public Service, ConEd, Carolina P&L, CSW, Dayton P&L, Detroit Edison, Florida Power Corp, NEPOOL, NE Public Power District, NERC, NYPP, Oklahoma G&E, Omaha PPD, PJM, Texas Utilities, Union Electric, VEPCO, and WP&L comments.

[83] *See* Central Illinois Public Service, Carolina P&L, and Ohio Edison comments.

[84] *See* ConEd, CSW, Florida Power Corp, NYPP, Ohio Edison, and PSNM comments.

[85] *See* APPA, CCEM, EGA, NCEMC, NIEP, OK Com, Seattle, Tallahassee, and United Illuminating comments.

[86] *See* Arizona, Dayton P&L, MidAmerican, NEPOOL, PJM, and Western Group comments.

[87] *See* Arizona, CCEM, Central Illinois Public Service, Com Ed, ConEd, CSW, Detroit Edison, NEPOOL, NE Public Power District, VEPCO, and WP&L comments.

[88] *See* APPA, Arizona, CCEM, Idaho, NEPOOL, Oklahoma Com, Seattle, and SoCal Edison comments.

[89] *See* Allegheny, Com Ed, Detroit Edison, NERC, NE Public Power District, Ohio Edison, SCE&G, Texas Utilities, Union Electric, and VEPCO comments.

Discussion

Additional information about the state of the transmission system will enable Transmission Customers to make better decisions about the quality of the transmission service they intend to purchase. However, the development and implementation of Phase I OASIS, in what is a relatively short period of time, requires that we limit the posting requirements of the OASIS to the essentials. We believe that audit data and information required to be provided about the reasons for curtailments and interruptions will make it possible to document unduly discriminatory practices concerning facilities critical to transmission capability. Also, as pointed out by APPA, the standards of conduct that we put in place with this rule lessen the urgency of posting additional information concerning generating unit status and transmission component status. Consequently, the Commission will not require the posting of information about the run status of generation and transmission facilities for a Phase I OASIS. We may reconsider this subject for Phase II OASIS depending on the Phase I experience.

7. Posting Transmission Service Schedules Information (§ 37.6(f))

The final rule consolidates and renumbers §§ 37.14(b) and (c) of the RIN NOPR as § 37.6(f). This provision requires information on scheduled transmission service to be recorded by the entity scheduling the transmission service and requires that the information be made available for download on the OASIS by interested parties. It also provides that postings must be made within one week of the start of the transmission service schedule agreed upon by the parties. The comments in response to the RIN NOPR did not take issue with the proposal. Thus, the provision is adopted without substantial revision.

8. Posting Other Transmission-Related Communications (§ 37.6(g))

Section 37.6(g) basically adopts what we proposed for the posting of ''want ads'' and ''other communications'' in § 37.9(f) of the RIN NOPR. Postings made in this section carry no obligation to respond on the part of any market participant.

This section provides that ''other communications related to transmission services'' (such as using the OASIS as a transmission-related conference space or to provide transmission-related messaging services between OASIS users) and ''want ads'' must be posted by the Responsible Party.

We received comments that urged the Commission to issue a disclaimer to the effect that, although Transmission Providers are responsible for posting other transmission-related communications at the request of third parties, it is the responsibility of the third parties requesting such postings to ensure the accuracy of the information to be posted. We agree that such a disclaimer is appropriate. We provide it in § 37.6(g)(2).

In addition, the final rule requires that transfers of personnel between the transmission and marketing functions are to be posted on the OASIS (§ 37.6(g)(3)). This incorporates the requirements of the standards of conduct at § 37.4(b)(2).

I. Section 37.7—Auditing Transmission Service Information

In the RIN NOPR, we proposed procedures that would govern the availability of records about auditing transmission service transactions.[90] The Commission proposed requiring that historical data on postings, updates, and request/response communications be recorded for audit purposes, be downloadable from the OASIS in an appropriate format for 60 days, and be available for download on a rolling basis for three years from entry on the OASIS. These provisions are now contained in § 37.7 of the final rule. However, we have increased the time during which audit data must be available for download from 60 days to 90 days because this provides greater protection to customers.

ConEd suggested that the Commission should provide assurance to Transmission Providers that they will not be liable if they post data under the proposed audit provisions that is considered confidential by their customers. We do not believe that it would be appropriate for the Commission to issue this sort of blanket disclaimer in the absence of any particular facts or controversy. However, to the extent that a Transmission Provider posts data because this is required by the Commission's regulations, the Transmission Provider may, of course, assert this as a defense against any legal action brought against it based on the disclosure.

J. Standards and Communication Protocols

In this section, we discuss the major issues raised in response to our proposed standards and protocols. As proposed, these are being issued in the separate *Standards and Protocols* document that we are issuing together with this final rule. As already described, the final rule states explicitly that information is to be posted on the OASIS in conformance with the specifications of the *Standards and Protocols*.

The most recent How Report (filed on April 15, 1996) shows great strides toward reaching consensus on a set of implementable standards. However, it needs to be augmented in two ways.

First, there are some internal inconsistences. For example, there are data elements that appear in the data dictionary that do not appear in the templates and vice versa. The data elements for DUNS numbers that appear in the data dictionary need to be added to the appropriate templates. Data elements for DUNS numbers for resellers need to be added to both the data dictionary and the appropriate templates. The October 16, 1995 How Report contained standards for Transmission Services Information Timing Requirements. The most recent report substantially changed these requirements. We request that the report we are asking the How Group to submit by May 28, 1996 reinstate these requirements or explain why they should be changed.

Second, and not surprisingly, the standards and protocols must now be conformed to the requirements of the final rule. For example, necessary changes include developing file and display templates for curtailments and interruptions, developing file and display templates to place primary and resale capacity on the same displays and in the same downloadable files, and developing file and display templates to place ancillary services provided by the primary provider and others on the same display page and in the same downloadable files.

Under procedures we are instituting today, we expect the recommendations for standards and protocols to be conformed to the requirements of the final rule and for inconsistencies to be corrected in the next few months. We are issuing portions of the standards and protocols now to provide as much information as possible to allow the industry to begin the work of building necessary systems to make their OASIS nodes operational. This information, coupled with the requirements of the Open Access Final Rule and our additional procedures to complete the *Standards and Protocols*, should result in the OASIS nodes being operational

[90] See RIN NOPR text at section III.C (60 FR at 66191) and the proposed regulation at 18 CFR 37.14 (60 FR 66201).

within six months of the publication of this final rule in the Federal Register.

The April 15, 1996 How Report contains references to a yet to be established industry group, the [OASIS] Management Organization, that will maintain a registry of [OASIS] node names and perhaps perform other functions associated with maintaining a functioning [OASIS]. We agree that there is a need for an industry group to maintain a registry of OASIS node names and perform similar functions and expect that such a group will be established by the industry prior to the implementation of the OASIS requirements. The *Standards and Protocols*, therefore, contains a reference to this function. We expect that such a group would be composed of representatives of all segments of the electric industry and we expect to be apprised of the group's activities.

1. Summary of Standards and Communication Protocol Requirements

The *Standards and Protocols*, which we are adopting together with this final rule, require Transmission Providers to make their OASIS nodes accessible through the Internet. Each Responsible Party's OASIS is considered to be a separate node. An OASIS operated jointly by several utilities would be considered one node. By connecting each node through the Internet, transmission service information provided by each utility becomes part of a network.

We are requiring that nodes must support the use of Internet tools. The specific tools are described in the *Standards and Protocols*. OASIS users will access nodes using World Wide Web (WWW) browsers.[91] Each node will display information using the Hypertext Mark-up Language (HTML) protocol required by World Wide Web browsers. Screen displays will consist of a series of pages that may be viewed by customers without requiring the page to be downloaded and viewed by separate software. The information on each page, but not the actual displays, will be standardized. Information must also be made available for downloading, in a standardized ASCII[92] format.

In Phase I, customers will have access to the information required to be posted by this rule and will be able to use the OASIS to reserve transmission capacity. They will be able to request capacity either by completing a standardized form contained in an on-line HTML page or by uploading a filled-out form using HTTP. Customers who want to resell transmission capacity will upload (post) the relevant information to the same OASIS node used by the primary provider from whom they purchased the ATC. Customers will also be able to upload other communications (*e.g.*, Want Ads) containing such information as requests to purchase transmission capacity.

OASIS nodes must provide direct connections to private networks if requested to do so. The cost of the connections will be paid for by the requestor and the networks are required to use Internet tools.

The *Standards and Protocols* contain a model of the information requirements that must be provided at each OASIS node. Customers are limited to obtaining information from HTML text displays and selecting from menus of downloadable files. Customers will receive the information either as HTML pages or as ASCII files in a predetermined form and layout.

For security purposes, and as an aid in auditing performance and transactions, all customers are required to register with the Responsible Party before they are permitted access to the utility's transmission service information on the OASIS. As registered subscribers, they will be allowed to read and download information, make requests for transmission service, place ''Want Ads'' and offer transmission service for resale. Commission staff and staff of state regulatory authorities are to obtain free ''read only'' access to the OASIS and members of the general public will also be provided ''read only'' access to the OASIS for the same usage fee paid by customers, once they have complied with the requisite registration procedures.

Responsible Parties are required to meet a number of performance standards and security precautions. Performance requirements include sizing OASIS nodes to handle the loading of registered subscribers, responding to subscriber requests, backing up the system, and other areas that are necessary for the system to function as desired.

2. Number of OASIS Nodes (Question 35)

The Commission proposed that Transmission Providers be permitted to combine their separate OASIS nodes into a single node. Thus, while there could be as many nodes as there are transmission-owning utilities, if utilities choose to combine together to create joint nodes, we could end up with a small number of nodes.

A small number of nodes would minimize the networking management requirements for the OASIS and would help ensure access to the information systems. On the other hand, the advantages of a small number of separate nodes must be weighed against the greater complexity and size of a joint node that would handle transactions for several large transmission-owning utilities at one node. The Commission requested comments on whether a small or large number of OASIS nodes should be encouraged.

The majority of commenters preferred a small number of nodes, but would not necessarily have the Commission require a small number of nodes.[93] Some commenters advocated regional nodes.[94] PJM speculated that, even if the Commission does not encourage a small number of nodes, economies of scale and market efficiencies will lead to smaller numbers in the normal course of events. The How Group reported that significant consolidation is already occurring:

> it appears there may be 1 node in ERCOT, 13–14 nodes in the Eastern Interconnection, and 6–20 nodes in the Western Interconnection. The resulting 20–35 nodes [nationwide] is a manageable number for Customers maneuvering through the system and at the same time minimizes the impact of possible security breaches or system failures by being sufficiently distributed.[95]

Given these comments, we believe that the question of whether there should be a small number of nodes is one best left to the industry. At this stage, flexibility in such matters is important.

3. Direct Connections to OASIS Nodes (Question 36)

The Commission explained in the RIN NOPR that private networks and third party services can provide valuable contributions to the successful operation of an OASIS.[96] The Commission, therefore, proposed to

[91] The World Wide Web is a system of computer resources that are accessed through the Internet.

A Browser is a computer program for retrieving and reading hypermedia documents from the WWW. A hypermedia document can contain text, graphics, video, sound or data. These documents are often linked to other documents.

[92] ASCII refers to the American Standard Code for Information Interchange, a code for character representation.

[93] *See, e.g.*, Allegheny, Central Hudson, Central Illinois Public Service, Com Ed, Continental Power Exchange, How Group, Florida Power Corp, Montana Power, NERC, NYPP, Ohio Edison, OK Com, PJM, PSNM, Seattle, Texas Utilities, and VEPCO comments.

[94] *See* APPA, CCEM, ConEd, CSW, and MAPP comments.

[95] How Group comments at 19.

[96] For example, a private network could connect to one or more OASIS nodes and offer users off-the-Internet connections at faster speeds. Third parties could gather OASIS information and repackage it into customized displays favored by individual users.

require utilities to provide direct connections to the OASIS without the need to obtain access through the Internet. We also proposed that the cost of these connections be paid for by the customers making the requests and that the networks be required to use the same Internet tools as the Internet connections.

Most commenters preferred that the Commission not require third-party connections to the OASIS in Phase I.[97] Com Ed asserted that direct connections would provide only marginal benefits to the development of an OASIS, and that adding such non-essential goals to OASIS requirements would jeopardize utilities' ability to implement an OASIS on time. Montana Power argued that direct connections would provide affluent large marketers with information ahead of smaller users, and thus would give them market power.

On the other hand, other commenters argued that such connections are important. ConEd argued that direct connections would help minimize the number of different connections customers must have. Continental Power Exchange sees direct connections as allowing third parties to provide services that will add valuable contributions to the successful operation of an OASIS. The How Group reported that discussions among the parties in the group indicated that direct connections would not be a problem as long as the Responsible Party is compensated for the additional service and given a reasonable time to make the connection.

All commenters addressing the subject of who should pay for direct connections agreed that the cost should be paid by the requesting party.[98]

CCEM and OK Com agreed that the direct connections should be required to use the Internet tools required for the Internet connection.

Finally, APPA asserted that, if private networks are created to provide direct connections that are operated by partners or affiliates of utilities, these networks could provide significant performance advantages for the Transmission Provider's merchant affiliates. APPA would require full public disclosure of such partnership or affiliate relationships by the service provider.

We find that the How Group's position is reasonable. Direct connections are feasible if the provider is compensated for the additional service and is given a reasonable time to make the connection. We will, therefore, require direct connections in Phase I, upon request.

Moreover, such connections must be made available on an equal basis to all requesting customers. We note, however, that to the extent that the Transmission Provider is not the Responsible Party, a direct connection is available only from the Responsible Party. This being the case, APPA's concern that the Transmission Provider's merchant services may gain an advantage from an affiliate with a direct connection or private network does not appear to be warranted, as anyone can obtain a direct connection or the services of a private network.

4. Value-Added OASIS Services Provided by Transmission Providers or Responsible Parties

The Commission proposed in the RIN NOPR to permit Transmission Providers or Responsible Parties to provide value-added OASIS services, such as higher speed connections and automatic notification of changed data.

NTEC argued that, unless these services are offered on a non-discriminatory basis, public utilities could gain a competitive advantage by offering these services solely to affiliates. NTEC also requested the Commission to monitor the ''basic'' and ''premium'' service packages to ensure that customers need not pay a ''premium'' price to obtain basic services.

TAPS argued against any offering of value-added services. They argued that smaller customers may not be able to afford such services and that price could be used to discriminate against them. TAPS proposed that instead of permitting value-added services, the Commission should include all OASIS costs in transmission rates.

We agree with NTEC that value-added OASIS services should be offered on a non-discriminatory basis. If a value-added service is offered to anyone, it should be offered to everyone on the same terms and conditions. Regarding NTEC's concern over basic and premium services, we believe that the standards setting process will ensure that the basic package of OASIS services will provide all pertinent information and the means to retrieve it that are necessary for the functioning of the Open Access program.

The Commission will allow these services on a non-discriminatory basis. Such services will remain cost-based until the Commission is satisfied that market-based (value added) rates should be allowed for such services. Requests for market-based rates for such services will be addressed on a case-by-case basis.

5. Transmission Services Information Timing Requirements (Question 37)

In the NOPR, the Commission requested comments on several timing requirements for posting transmission service information. These are:

(1) Transmission Service Information Availability: The most recent Provider transmission service information, including updates reflecting power system changes, shall be available to all Customers within 5 minutes of its scheduled posting time at least 98 percent of the time. The remaining 2 percent of the time the transmission service information shall be available within 10 minutes of its scheduled posting time;

(2) Notification of Posted or Changed Transmission Service Information: Notification of transmission service information posted or changed by a Provider shall be made available within 60 seconds to all subscribed Customers who are currently connected; and

(3) Acknowledgment by the Transmission Service Information Provider: Acknowledgment by the transmission service information provider of the receipt of Customer purchase request/response requests shall occur within 1 minute for Phase I. The actual negotiations and agreements on purchase request/response requests do not have time constraints. For Phase II, acknowledgment shall occur within 30 seconds.

Most commenters supported the Commission's proposals as proposed[99] or with some modification.[100] CCEM asserted that the proposed requirements for updating transmission service information contained in Item (1) would lead to stale information, and would result in customers using the telephone and not the OASIS. CCEM asserted that the Phase I tolerances should be reduced to 30 seconds and one minute respectively.

Continental Power Exchange asserted that items (1) and (2) are good starting points. The Western Group suggested that Item (1) would be adequate if it can be accomplished automatically. Otherwise, it would recommend reducing the 98 percent compliance requirement to 85 percent.

Some commenters agreed with the need for such standards, but opposed

[97] *See, e.g.,* Allegheny, Com Ed, Montana, NERC, Ohio Edison, OK Com, PJM, PSNM, and VEPCO comments.

[98] *See* APPA, CCEM, ConEd, Continental Power Exchange, How Group, and PJM comments.

[99] *See, e.g.,* APPA, Duke, How Group, Florida Power Corp, NYPP, and OK Com comments.

[100] *See* CCEM, Com Ed, Continental Power Exchange, PSNM, and Western Group comments.

incorporating timing performance standards in Phase I standards. VEPCO asserted that these standards are too ambitious for Phase I. Tallahassee argued that these timing requirements may be too restrictive for small utilities whose staff and technology capabilities will be strained by this rule. Central Hudson proposed that response times be determined after OASIS is implemented and users are comfortable with what they would expect as adequate performance.

Most commenters agreed on the need for standards for how quickly providers should post transmission service information. Commenters argued that the requirements should be stricter, that they are too strict, or that they are just right.

The Commission stated that information posting performance requirements are needed to ensure that information is disseminated in a timely manner by Transmission Providers. The comments do not persuade us to change the proposed requirements. We note that the April 15, 1996 How Report drops these requirements. We request the How Group to reinstate these requirements in the report we are inviting them to file on or before May 28, 1996, or to explain why these requirements should be dropped.

Commenters raise several additional points that need to be addressed. First, Com Ed and others argued that these requirements should not be in force during emergencies. The Commission agrees.

Second, several commenters pointed out that the phrase ''available to all Customers'' contained in Item (1) is ambiguous and request that it should be replaced by ''available on the [OASIS].'' We agree.

Third, some commenters suggested that transmission service requests and schedules be approved automatically, on a first come, first served basis. The industry does not generally do business in this manner today, and the Commission will not require it in Phase I. We request the industry to address this issue when developing requirements for Phase II.

6. Common Codes

a. Company Codes

The Commission's experience with implementing standards for file transfers and electronic bulletin boards in the natural gas industry shows that the use of a common system of identifying companies enhances the efficiency of data transfers. The Commission is satisfied with the results of using DUNS numbers [101] as the standard to uniquely identify pipelines and shippers in the natural gas transactions.[102] The Commission proposed to require the use of DUNS numbers to identify transmission-owning utilities and customers on OASIS nodes.

Most commenters believed that DUNS numbers alone or DUNS numbers in combination with names should be used.[103] The How Group asserted that using DUNS numbers will enhance the management of data from a computer perspective and allow flexibility of business applications of OASIS in the future. The How Group also asserted that having commonly used names is more user friendly and proposed that the list of names and DUNs numbers be maintained on a centralized registry.

Others believed that names alone would be sufficient.[104] NERC and Ohio Edison believed that such standardization should be left to the industry.

APPA asserted that DUNS numbers are primarily for private companies and do not include many public power systems. Instead of using DUNS numbers, APPA recommended using a numbering system derived from Energy Information Administration forms: EIA–861 (''Annual Electric Utility Report'') and EIA–867 (''Annual Nonutility Power Producer Report'') as these forms appear to be the most all-encompassing existing numbering system that could be used for OASIS identification. Dun and Bradstreet have informed staff that they will assign DUNS numbers, free of charge, to any entity requesting a number.

The Commission will require the DUNS numbers as the unique numerical identification of OASIS participants. The industry can proceed to develop a naming convention as suggested in the comments.

b. Common Location Codes

The Commission's experience in the natural gas industry demonstrates that a common method of uniquely identifying location points will be needed to facilitate movement of power across the grid. The Commission proposed to use a system to identify locations and paths on the electric transmission grid.

Nearly all commenters who discussed the issue argued that the Commission should not require common location codes.[105] Several commenters argued that providing longitude and latitude information for power plants and substations raises serious national security issues.[106]

Many commenters see the need for a common naming convention for paths and other facilities, such as that currently under development by the How Working Group.[107]

The Commission is persuaded to drop the requirement for a system for location codes and requests the industry to continue development of a common naming convention to be implemented as soon as practicable.

7. Data Definitions and File Formats Not Covered by the Revised How Report

a. Offers to Provide Ancillary Services Provided by an Entity Other Than the Transmission Provider (Question 11)

In the RIN NOPR, the Commission requested the specifications needed to post this information in HTML displays and the formats needed to standardize uploadable and downloadable files containing this information. This final rule requires that information about ancillary services provided by an entity other than the Transmission Provider be posted on the OASIS by Responsible Parties and be displayed on the same page and in the same file format as that of the Transmission Provider.

Although we did receive comments on this issue from various parties, this was not an issue resolved by the revised How Report. We would prefer that the How Group attempt to reach consensus on this issue before we impose our own solution. Therefore, we will include this issue among those that we are requesting further input on before we address this issue in the *Standards and Protocols*.

b. Offering of Primary and Secondary Capacity

The Commission requested comments on how to redesign the download templates in Appendix C of the NOPR so that primary and secondary capacity can be offered through downloadable files that have the same format. The Commission also requested comments on how primary and secondary capacity

[101] DUNS numbers refer to the Data Universal Numbering System, maintained by Dun and Bradstreet.

[102] *See* Standards for Electronic Bulletin Boards Required Under Part 284 of the Commission's Regulations, Docket No. RM93–4–001, Order 563–A, FERC Stats. & Regs., Regulations Preambles, ¶ 30,994 at 31,034 (1994).

[103] *See, e.g.*, Allegheny, CCEM, Com Ed, Continental Power Exchange, How Group, OK Com, and PJM comments.

[104] *See* Seattle, VEPCO, and Western Group comments.

[105] *See* Allegheny, APPA, CCEM, Continental Power Exchange, Duke, How Group, ERCOT, Florida Power Corp, NERC, PJM, VEPCO, and Western Group comments.

[106] *See* How Group, FPC, and NERC comments.

[107] *See* How Group, PSNM, and Western Group comments.

can be displayed in the same tables on an OASIS node. Posting secondary capacity requires more information than for primary capacity and, thus, using the same formats would require many more fields. We need information on the design of those fields before we can set standards for the display of this information.

Although we did receive comments on this issue from various parties, this was not an issue resolved by the revised How Report. We would prefer that the How Group attempt to reach consensus on this issue before we impose our own solution. Therefore, we will include this issue among those that we are requesting further comment on before we address this issue in the *Standards and Protocols.*

8. Formats for Downloadable Files Not Covered in the How Report

a. Standard Format for Data Used in Calculating ATC (Question 16)

The Commission requested comments on how the data used in calculating ATC should be formatted and asked whether the information should be in free form text, predefined tables, or comma delimited ASCII files. We also asked whether, if the information is in free form text, it should be in plain ASCII text or in a word processor format, such as WordPerfect or Word. We deal with both of these issues in section H(2)(f) of this final rule and in the regulations at § 37.6(b)(2)(ii).

b. Standard Formats for Transmission Studies (Question 23)

The Commission requested comments on how transmission studies should be formatted for download from the OASIS. We deal with this issue in section H(2)(g) of this final rule and in the regulations at § 37.6(b)(2)(iii).

c. Standard Format for Electronic Submission to the Commission of Transmission Tariffs (Question 6)

In the RIN NOPR, the Commission proposed requiring that Transmission Providers provide downloadable files of their complete tariffs on the OASIS.[108] The Commission requested that commenters propose a standard format for electronic submission of transmission tariffs to the Commission.

New formats continually are being developed by the computer industry and it would be worthwhile to address this issue again when the Commission addresses Phase II or remaining OASIS issues.

We will require utilities to provide tariff downloads from their OASIS in the same format that they use to file with the Commission.

9. Communication Protocol Issues

a. Internet Browsers

There are a large number of Internet browsers available commercially and in the public domain. The How Report proposed that browsers support ''at least'' HTML version 3 and ''optionally'' support Secure Sockets Layer. The HTML standards used by browsers change from time to time, and, in addition, various browsers can support different extensions to the standards. The Commission does not want to stifle innovation, but at the same time it does want uniformity on the OASIS. The Commission does not want customers to be forced to use different browsers for different OASIS nodes. The Commission wants to ensure that a customer will be able to choose a browser and use it to access all OASIS nodes.

To this end, the Commission requested comments on how to ensure that a customer will be able to choose a browser and use it to access all OASIS nodes.

Most commenters agreed that requiring browsers to support HTML 3 would be sufficient to meet the needs of OASIS nodes and customers at this time.[109]

CSW reported that while the specifications for HTML 3 are still in draft mode, it is the first version of HTML to support the table feature for browsing that the How Working Group wants to use. NYPP would add encryption capabilities to the list of standards. Ohio Edison would require JAVA-enabled browsers.[110]

OK Com recommended that the Commission adopt a primary browser and two alternative browsers for use on OASIS nodes. PJM asserted that, by requiring OASIS nodes to accommodate browsers in common use, OASIS nodes would be able to become more sophisticated as the Internet itself becomes more sophisticated.

Com Ed, ConEd and PSNM would leave the standard to the How Group or an industry-wide OASIS Management Organization.

Most commenters agreed with the How Report that, requiring OASIS nodes to support HTML 3 will allow browsers supporting this standard to view documents on the OASIS. The Commission will adopt the recommendation for HTML 3 contained in the How Report.

b. Bandwidth of Node Connections to the Internet

At issue is the speed at which OASIS users will receive information from OASIS nodes. A major determinant of the speed are the bandwidth connections between the OASIS node and the Internet. The How Report proposed a formula to compute the required minimum bandwidth based on the number of registered users of the node and the number of bits per second to be received by users during HTML displays and downloads of files.[111] These information transfers would include both the receipt of HTML displays and downloads of files. The How Report proposed to use a rate of 8,000 bits per second to determine bandwidth. In the RIN NOPR, the Commission noted that an 8,000 bit per second transfer rate is a much slower rate than the 28,800 bit per second transfer rate for telephone connections that many private individuals and customers use to connect to the Internet. The Commission expressed concern that using 8,000 bit per second as the basis for the bandwidth calculation will lead to connections that are too slow and proposed to use 28,800 bits per second.

Many commenters agreed with the Commission.[112] Com Ed reported that a T1 communications line (1.54 million bits per second) could support 500 simultaneous customers using the Commission's proposal of using 28,800 bits per second in the bandwidth formula. Com Ed concluded that it is unlikely that an OASIS node will experience 500 simultaneous users and that a T1 line is a reasonable upper limit, at this time. The How Group reported that its members are currently paying between $1,500 and $3,000 per month for T1 connections and concludes that it may be cost effective to oversize the bandwidth even though a high bandwidth does not automatically translate into higher access speeds or download rates.

Several commenters preferred the 8,000 bits per second originally proposed by the How Group.[113] Ohio Edison suggested that using a speed of 28,800 will dramatically increase costs and may make joint OASIS nodes less attractive. The How Group asserted that experience has shown that 8,000 bits per second is a reasonable average rate

[108] *See* RIN NOPR text at section III.C (60 FR at 66186) and the proposed regulation at 18 CFR 37.9(c)(1) (60 FR 66200).

[109] *See, e.g.,* Allegheny, APPA, CCEM, and How Group comments.

[110] JAVA is a language that enables a browser to run programs embedded in a WWW page.

[111] How Report at § 3.4.3.

[112] *See, e.g.,* Allegheny, APPA, CSW, OK Com, PJM, and Seattle comments.

[113] *See* ConEd, How Group, and Ohio Edison comments.

for users of the Internet. VEPCO stated that, while many customers will initially use modems rated at 28,800 bits per second, their average data transfer rate will be lower due to a number of factors. Nevertheless, VEPCO asserted that an average of 8,000 bits per second is on the low end of acceptability, especially if large files are to be downloaded or if graphics files are to be viewed. Continental Power Exchange proposed that the 19,200 bits per second be used in the formula. It asserted that this is the fastest modem speed achievable with Microsoft's Windows 3.1.

APPA speculated that there may some areas in remote locations that cannot secure a connection to the Internet with adequate bandwidth to support the 28,800 bit per second standard.

After considering the comments, the Commission continues to believe that 8,000 bits per second is too slow, especially when large files must be transferred and when information is needed promptly for business decisions. The Commission, therefore, will require that a rate of 28,800 bits per second be used in the minimum bandwidth calculation.

c. Data Compression Standards

In the RIN NOPR, the Commission expressed agreement with the How Report that data compression will speed up the transmission of files.[114] We also expressed the belief that communication of OASIS information would be enhanced if every OASIS node used the same compression techniques. The Commission requested comments on what data compression technique or techniques should be made standard for all OASIS nodes.

Most commenters recommended that the ''ZIP'' file compression standard be adopted as the common OASIS standard.[115] The How Group pointed out that the ZIP format is available for most computer platforms. Some commenters, however, suggested that setting a common compression technique is too detailed for a Commission rulemaking.[116]

Most commenters supported using the ''ZIP'' file compression standard on OASIS. This format is widely used for data communication and the necessary software is available for most computer platforms. The Commission will, therefore, require that the ZIP standard be the data compression standard on OASIS nodes. The Commission agrees that requiring compression for files created for each HTTP request may be too complex for Phase I. However, utilities may want to compress large files that would be infrequently updated, such as tariffs. These files will benefit from file compression and will not be subject to the complexities of compressing the dynamically created HTTP files. The Commission will require that static files residing on OASIS nodes be compressed.

d. Other Communication Protocol Issues Raised by Commenters

i. The Requirement to Use FTP for File Transfers

The October 16, 1995 How Report recommended requiring OASIS nodes to use the Internet File Transfer Protocol (FTP) for file uploads and downloads. In its comments, the How Group recommended changing the file transfer method originally proposed in the How Report from the FTP to the HTTP for data access, including files upload and download to and from OASIS nodes. We will accept this recommendation.

ii. Field Size for Path Names

The How Report proposed that path names be a 12-character alphanumeric string. The March 7, 1996 filing by its How Group recommends that the 12 characters be changed to 50 alphanumeric characters. Subsequent to the How Report, the How Group found that 12 characters were insufficient to accommodate path names and the associated regional identifiers.

We will await final recommendations concerning file formats before ruling on this issue.

iii. Files Containing More Than 100,000 Bytes

The How Report recommended that customers not be required to download any single file that is larger than 100,000 bytes in order to access transmission information in electronic form. The implication is that all files larger than 100,000 bytes must be broken into sub-files.

Detroit Edison argued that there is no easy way to download only a section of a file and that customers may prefer to download one large file rather than 20 small ones.

We agree and will not require files to be broken into 100,000 byte segments at this time. In the event that a restriction on file size becomes needed, it can be addressed in Phase II.

K. Cost Recovery Issues

1. Costs of Developing and Running an OASIS (Question 34)

Transmission-owning public utilities are entitled to recover the costs of developing and running an OASIS. Generally, these costs will be fixed costs not attributable to individual users. In the NOPR, the Commission proposed to include these costs in wholesale transmission rates. The Commission also proposed to allow costs that can be identified as varying with usage to be charged as usage fees to individual customers.

The commenters were nearly evenly split between those favoring and opposing the Commission's proposals. NIEP argued that rolling-in OASIS costs would distribute costs among all transmission users equally and would be the only fair method of allocating the cost of an OASIS. NIEP concludes that, if costs were directly assigned to individual transmission users, these users would be penalized by forcing them to pay the cost of providing information which is available to, and used by, all transmission users.

Many commenters objected to including OASIS costs in wholesale transmission rates. They argued that it is inappropriate to require network service customers (who may not participate in wholesale sales transactions) to absorb the cost of the OASIS. Indianapolis P&L claimed that it has no significant, unique transmission paths and uses its transmission assets to serve its native load customers. Consequently, most of its OASIS costs would be borne by its native load customers.

Many commenters suggested alternatives to rolling in OASIS costs. ConEd argued that, if all OASIS costs were included in wholesale transmission rates, OASIS costs might not be fully recovered since transmission use varies. To remedy this, ConEd proposed rolling in part of the costs with the remainder to be recovered through a monthly access fee. MAPP suggested usage fees based on cost causation, such as time access charges, fixed fees for transmission requests and fees based on energy scheduled over transmission secured on the OASIS. NSP suggested a fee structure like other on-line information services, such as America On Line, CompuServe, and Prodigy.

Several commenters saw other problems associated with utility recovery of OASIS costs. Some called attention to potential problems in recovering the costs of a joint OASIS. MAPP pointed out that a jointly

[114] How Report § 3.3.8(c).

[115] *See* APPA, CCEM, ConEd, and PSNM comments.

[116] *See* NERC and Ohio Edison comments.

operated OASIS will not have composite transmission tariffs from which to recover costs and that a method was needed for utilities to recover joint expenses.

Detroit Edison speculated that a large number of the general public could be connected to an OASIS at one time and thus limit OASIS access to transmission users. To prevent this problem, Detroit Edison proposed that fees be established to prevent misuse or overuse of an OASIS.

It is appropriate that all wholesale transmission customers and all unbundled retail transmission customers should pay a share of OASIS development costs in their rates. Therefore, the Commission concludes that the cost of developing an OASIS should be included in unbundled transmission rates with variable costs of operating an OASIS to be recovered, to the extent possible, in usage fees. Individual rate proceedings will determine which OASIS costs can be identified as varying with usage and how to set the fees.

2. Costs of Posting Resales of Capacity on the OASIS (Question 40)

The Commission proposed that resales of capacity be posted on the same page, and using the same display and downloadable tables, as capacity being sold by the Transmission Provider. This posting incurs an expense on the part of the Responsible Party. The Commission proposed that each reseller must, therefore, pay the costs of posting its own offering.

Most commenters believed that those posting secondary services should pay the cost of posting. APPA proposed that the incremental cost of posting should be recovered as a special fee in the primary contract of transmission service. Ohio Edison proposed a fee for each posting with a ''true up'' mechanism to ensure that over time actual costs are recovered. Com Ed and WP&L suggested a fee that is a percentage of revenue received from the secondary postings.

NEPOOL suggested that this expense is unlikely to be significant and, therefore, could be included in rates. NRECA and NCEMC warned that posting fees not be set so high as to discourage resale of capacity. OK Com argued that it would be inappropriate to charge resellers of transmission capacity for posting if the Transmission Provider is not also required to pay a fee for posting.

After considering the comments, we have decided that there should be no added fee for posting capacity resales. All OASIS users, including the Transmission Provider, who post capacity pay all the fixed costs of OASIS in wholesale rates and pay usage-related variable costs in access fees. Thus, the costs of posting resale capacity are already recovered. To require resellers to pay additional fees for posting their products would provide OASIS operators with a cost advantage.

3. Costs of Posting Ancillary Services on the OASIS

The Commission proposed that entities posting offers to provide ancillary services on the OASIS should pay the costs associated with posting this information and requested comments on how to determine these costs.

Commenters proposed various fee schemes to recover these costs. Some were based on the cost of developing and maintaining posting services, others were based solely on the incremental cost of posting a notice. Some proposed to roll the costs into wholesale transmission rates. Others proposed that utilities be allowed make a profit from this service.

Arizona proposed an incentive scheme to keep costs down, while Continental Power Exchange suggested that the method of calculating these costs be left to the industry. PJM proposed a fee based on the amount of person-hours and computer usage required by such posting. ConEd argued that utilities should be allowed to earn a profit on this service.

CSW submitted that posting costs cannot be broken out individually and proposed that the costs for an OASIS should be borne by all market participants on a fair basis. Florida Power Corp argued that an OASIS is not a newspaper, and that Transmission Providers are not in the publishing business; therefore, OASIS services, including the posting of ancillary services, should not be sold like classified ads. It proposed that the cost of operating an OASIS should be rolled into wholesale transmission rates. VEPCO also suggested that the cost of posting ancillary services should be included in the cost of the OASIS, with costs of specific evaluations of ancillary service offers to be determined and posted on the OASIS.

After assessing the comments, we find that the cost of developing the facilities needed to post ancillary services required to be provided by the Open Access Final Rule should be recovered through unbundled transmission rates. Any variable costs of posting these services will be included in the general OASIS usage fees. As for those ancillary services not required to be provided,[117] OASIS operators may charge a cost based fee to those offering these services for the cost of posting.

L. Section 37.8—Implementation in Phases

1. Phase I Implementation

Implementation of this rule and the initial standards and protocols will ensure that sufficient information is available to transmission customers to achieve comparable access to transmission information. They do not, however, provide all the desired performance requirements.

Because of the complexity of developing an OASIS, and the need to begin the transmission open access program promptly, the Commission proposed a phased approach to OASIS implementation. We proposed to require implementation of a Phase I OASIS as of the effective date of the final rule on non-discriminatory open access transmission and stranded costs (*i.e.*, 60 days from publication of this order in the Federal Register).

Comments

Many commenters argued that the proposed 60-day implementation period is unrealistic in light of the amount of work that must be done. ERCOT suggested that only portions of the Phase I implementation could be accomplished within the 60-day period. A vast majority of commenters suggested that an implementation period of six months would be required.

Arizona and ConEd pointed out that, while plans for implementation can begin in advance of the final rule, final specifications and designs depend on the resolution of several major Open Access Final Rule issues. ConEd also argued that all new systems require a ''Beta'' test stage in which the system can be tested before it is used in a production environment, and that a 60-day implementation period will not permit such testing. Similarly, NERC argued that more time is needed to make sure workable administrative procedures are in place for consistency in calculating, posting, and coordinating ATC. NEPOOL echoed these comments, reporting that an implementation period of less than six months would result in the development of OASIS nodes across the nation that lack uniformity as each region complies within a short deadline without time to coordinate with other areas.

Duke argued that a full six months will be needed because, in addition to

[117] *See* Open Access Final Rule generally at section IV.D.

the difficult task of implementing OASIS, the Open Access Final Rule will change the way the industry does business. Duke argued that the coordination of resources necessary to accommodate all of the discussions and decisions in developing joint OASIS nodes is a more lengthy process than development of an OASIS by each individual company. Duke asserted that a six-month implementation period is needed to permit joint OASIS projects to develop. [118]

SoCal Edison requested that the Commission delay implementation until the requirements of the CA Com's California Restructuring Order have been fully identified. Public Generating Pool argued that the Northwest governors have organized a review of the Northwest Power Act, the Bonneville Power Act, and the northwest electric system in general, to be completed by November 1996. Public Generating Pool argued that the Commission should consider possible contributions to be made by this forthcoming report and urged that the Commission not ignore this work based on a need to meet self-imposed unreasonable and unrealistic OASIS implementation dates.

The How Group, the Western Group and VEPCO suggested that, if the Commission cannot extend the implementation period to six months, then Phase I should itself be implemented in stages. The How Group suggested a three-stage process that would begin with a requirement for primary providers, within 120 days after issuance of the final rule, to post estimates of ATC and secondary capacity for resale that might not be accurate. This would be followed, within 180 days after issuance of the final rule, by the posting of fully accurate secondary capacity information and ATC information, and with Transmission Providers certifying, within 210 days of the final rule, that all functionality and performance requirements for OASIS have been met.

ConEd and Carolina P&L noted that OASIS implementation will cause changes to utility operations, and requested that the Commission schedule implementation during off-peak seasons, such as the spring or fall, when they claim transmission systems are under less stress.

Public Generating Pool and Tallahassee speculated that, if publicly-owned utilities are considered to be under the Commission's jurisdiction for OASIS purposes, they will need more than a six-month implementation period because they may be required to obtain funding approval from state or local oversight commissions.

Discussion

Commenters make persuasive arguments for permitting a six-month implementation period. They raise concerns that a shorter period will not permit adequate time to design, build and thoroughly test an OASIS. They also raise concerns that a shorter period will inhibit the development of joint OASIS and OASIS with a common look and feel. The Commission shares these concerns. We also want to take into account commenters' requests that implementation not be required during the peak winter or summer months. For this reason, we are requiring compliance by November 1, 1996, a specific date about six months from when we expect this final rule to become effective, chosen to avoid the winter and summer peak months. This date is provided in § 37.8 of the final rule, which modifies the provision originally set out in § 37.15 of the RIN NOPR.

In addition, we will provide additional procedures to allow the development of the remaining initial standards and protocols. As described above, we invite the How Group to report to us on or before May 28, 1996 on these issues (and to attach any comments it has received from any interested person with opposing views).

For these reasons, the Commission will require implementation of Phase I of OASIS to be operational by November 1, 1996.

2. Phase II Implementation

Once Phase I becomes operational, and the industry and public gain experience with it, the full information and functional requirements needed to support open access transmission service will become clearer. In the RIN NOPR, the Commission stated that it envisioned that Phase II would build on Phase I and requested that the industry continue the process of developing standards, and provide a consensus report to the Commission on Phase II recommendations by January 1, 1997.

Most commenters argued that the proposed January 1997 date is too ambitious. Southern argued that this date does not provide enough time for the industry to gain experience with Phase I. Tallahassee and others suggested that Phase II should not be implemented until at least one year after Phase I is implemented. Continental Power Exchange asserted that Phase II will be a continuum of development from the first day of Phase I implementation. NRECA suggested that, if Phase I turns out to be inadequate, then Phase II should be accelerated.

We are sensitive to commenters' concerns about the time between the implementation of Phase I and Phase II. At the same time, the need for the additional functions and performance requirements proposed for Phase II will, we believe, need to be implemented quickly. Accordingly, the industry should continue the process of developing standards, and attempt to develop a consensus report on Phase II recommendations by no later than seven months after implementation of Phase I June 4, 1997. We anticipate that this report would be the basis for supplemental OASIS proceedings to Phase II OASIS requirements. The additional time should permit the industry to obtain sufficient experience with Phase I before it recommends specifications for Phase II.

We believe that it may be appropriate to require the scheduling of energy transfers on the OASIS in Phase II. Electronic scheduling of energy transfers over the OASIS would increase efficiency. We, therefore, request that the industry incorporate standards for the scheduling of energy transfers on OASIS into the Phase II report.

IV. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) [119] requires the Commission to describe the impact that any proposed or final rule would have on small entities or to certify that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. The entities that would have to comply with the final rule are public utilities and transmitting utilities that do not fall within the RFA's definition of small entities.[120] Therefore, under section 605(b) of the RFA, the Commission hereby certifies that this final rule will not have a significant economic impact on small entities within the meaning of the RFA. Accordingly, no regulatory

[118] NERC made this same point in its comments.

[119] 5 U.S.C. §§ 601–612.

[120] *See* 5 U.S.C. §§ 601(3) and 601(6) and 15 U.S.C. § 632(a). The RFA defines a small entity as one that is independently owned and not dominant in its field of operation. *See* 15 U.S.C. § 632(a). In addition, the Small Business Administration defines a small electric utility as one that disposes of 4 million MWh or less of electric energy in a given year. *See* 13 CFR 121.601 (Major Group 49–Electric, Gas and Sanitary Services) (1995).

In the Open Access Final Rule, issued contemporaneously with this final rule, we conclude that, under these definitions, the Open Access Final Rule would not have a significant economic impact on a significant number of small entities. As this final rule only implements the OASIS requirements of the Open Access Final Rule, the same conclusion is warranted here, for the same reasons.

flexibility analysis is required pursuant to section 603 of the RFA.

In its comments, NRECA questioned the Commission's conclusion that the RIN NOPR did not need to be accompanied by an RFA analysis. NRECA's argument was based on its concern that the Commission might extend OASIS requirements to non-public, not-for-profit cooperative utilities. NRECA argued that, if this were to happen, the Commission would then have to analyze the effect of the OASIS requirements on these utilities and show that the requirements would not have a substantial economic impact upon them. However, as proposed in the RIN NOPR, the Commission's OASIS regulations will apply only to public utilities that own, operate, or control transmission facilities subject to the Commission's jurisdiction. As noted immediately above, public utilities do not fall within the RFA's definition of a ''small entity.'' In addition, as discussed earlier, and as discussed in the Open Access Final Rule, there will be a provision for a waiver for small entities. This responds to NRECA's concerns.

V. Environmental Statement

Commission regulations require that an environmental assessment or an environmental impact statement be prepared for a Commission action that may have a significant effect on the human environment.[121] Although this final rule does not directly affect any physical transmission facilities, but merely requires the electronic posting by computers of certain information about transmission availability and prices, it nevertheless is covered by the Final Environmental Impact Statement issued in the Open Access NOPR proceeding in Docket Nos. RM95–8–000 and RM94–7–001 on April 12, 1996. Thus, no separate environmental assessment or environmental impact statement has been prepared in this proceeding.

VI. Information Collection Statement

There are now approximately 328 public utilities, including marketers and wholesale generation entities. The Commission estimates that approximately 166 of these utilities own, operate, or control facilities used for the transmission of electric energy in interstate commerce and thus are subject to this rule. However, since the operation of an OASIS will be closely associated with control areas, we assume that an OASIS will be developed at the control area level and not by each public utility that owns, operates, or controls interstate transmission facilities. We also expect that some additional OASIS nodes will be created voluntarily by non-public utilities subject to these regulations under the reciprocity condition of the *pro forma* tariffs. We estimate, therefore, that 140 respondents will be required to collect information. We believe that this estimate is conservative (on the high side) because some regions are likely to develop a region-wide OASIS that will cover more than one control area.[122]

This estimate is higher than the one we included in the RIN NOPR, where we estimated that there would be 84 respondents. We have adjusted our estimate in response to the arguments advanced by NRECA and NE Public Power District, in separate letters to OMB, that the Commission's Information Collection Statement contained in the RIN NOPR failed to account for the proposal in the Open Access NOPR that, because of the reciprocity requirement, non-public utilities and cooperatives entering contracts for open access transmission services would be required to establish their own OASIS nodes or participate in a regional OASIS node.

NRECA also argued that the Commission's analysis must include not only those entities that are developing their own OASIS node, but also those entities who, while they are not developing and operating their own OASIS node, nevertheless will contribute data to their control area operators or regional OASIS operators. NRECA argued, therefore, that the Commission's estimate of the number of respondents should have taken this into account. It did.

Although not explicitly stated in the RIN NOPR, the Commission's Information Collection Statement, both in this final rule and in the RIN NOPR, has been based not only on the efforts by the respondents who will directly operate OASIS nodes but also reflects the collection of information from all significant participants in the transmission market.

Information Collection Statement

Title: FERC–717, Real-Time Information Network Standards.

Action: Final Rule

OMB Control No: 1902–0173.

Respondents: Public Utilities that own and/or control facilities used for the transmission of electric energy in interstate commerce.

Frequency of Responses: On Occasion

Necessity of the information: The final rule requires affected public utilities to comply with requirements for an Open Access Same-time Information System (OASIS) established by the Commission to give potential customers access to information, by electronic means, that would ensure the availability of open access wholesale transmission service on a non-discriminatory basis. These requirements would support arrangements made for wholesale sales and purchases for third parties. Public utilities or their agents will be required to give competitors and other users of the transmission system access to the same information available to public utility personnel who initiate the acquisition or disposition of power in the wholesale market and at the same time. The Commission will use the information to monitor the networks to ensure that potential purchasers of transmission services obtain the services on a non-discriminatory basis. This final rule was developed after a review of comments filed in response to issuance of a notice of public rulemaking.

The Office of Management and Budget's (OMB) regulations,[123] require OMB to approve certain information collection requirements imposed by agency rule. The information collection requirements in the final rule will be reported directly to transmission users and will be subject to subsequent audit by the Commission. The distribution of these data will help the Commission carry out its responsibilities under Part II of the FPA.

The Commission is submitting notification of this final rule to OMB. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention Michael Miller, Information Services Division, (202) 208–1415], and to the Office of Management and Budget [Attention: Desk Officer for the Federal Energy Regulatory Commission (202) 395–3087].

VII. Effective Date

The regulations of new part 37 will become effective on July 9, 1996. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that the Open Access Final Rule and the OASIS final rule together constitute a ''major rule'' as

[121] Regulations Implementing National Environmental Policy Act, Order No. 486, 52 FR 47897 (Dec. 17, 1987); 1986–90 Regulations Preambles, FERC Stats. & Regs. ¶30,783 (Dec. 10, 1987) (*codified* at 18 CFR Part 380).

[122] *See supra* (discussion quoted from How Report at 80).

[123] 5 CFR 1320.11.

defined in section 351 of the Small Business Regulatory Enforcement Act of 1996.[124] The rule will be submitted to both Houses of Congress and the Comptroller General prior to its publication in the Federal Register. All of the requirements prescribed in the standards of conduct must be complied with and Phase I OASIS sites that meet the requirements prescribed in this final rule must be in operation by November 1, 1996.

List of Subjects in 18 CFR Part 37

Electric power plants, Electric utilities.

By the Commission.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends chapter I of title 18, *Code of Federal Regulations,* to add a new part 37, as set forth below:

PART 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEMS AND STANDARDS OF CONDUCT FOR PUBLIC UTILITIES

Sec.
37.1 Applicability.
37.2 Purpose.
37.3 Definitions.
37.4 Standards of conduct.
37.5 Obligations of Transmission Providers and Responsible Parties.
37.6 Information to be posted on an OASIS.
37.7 Auditing Transmission Service Information.
37.8 Implementation schedule for OASIS requirements; phases.

Authority: 16 U.S.C. 791–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

§ 37.1 Applicability.

This part applies to any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce and to transactions performed under the *pro forma* tariff required in part 35 of this chapter.

§ 37.2 Purpose.

(a) The purpose of this part is to ensure that potential customers of open access transmission service receive access to information that will enable them to obtain transmission service on a non-discriminatory basis from any Transmission Provider. These rules provide standards of conduct and require the Transmission Provider (or its agent) to create and operate an Open Access Same-time Information System (OASIS) that gives all users of the open access transmission system access to the same information.

(b) The OASIS will provide information by electronic means about available transmission capability for point-to-point service and will provide a process for requesting transmission service. OASIS will enable Transmission Providers and Transmission Customers to communicate promptly requests and responses to buy and sell available transmission capacity offered under the Transmission Provider's tariff.

§ 37.3 Definitions.

(a) *Transmission Provider* means any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce.

(b) *Transmission Customer* means any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service.

(c) *Responsible party* means the Transmission Provider or an agent to whom the Transmission Provider has delegated the responsibility of meeting any of the requirements of this part.

(d) *Reseller* means any Transmission Customer who offers to sell transmission capacity it has purchased.

(e) *Wholesale merchant function* means the sale for resale, or purchase for resale, of electric energy in interstate commerce.

(f) *Affiliate* means:

(1) For any exempt wholesale generator, as defined under section 32(a) of the Public Utility Holding Company Act of 1935, as amended, the same as provided in section 214 of the Federal Power Act; and

(2) For any other entity, the term *affiliate* has the same meaning as given in § 161.2(a) of this chapter.

§ 37.4 Standards of conduct.

A Transmission Provider must conduct its business to conform with the following standards:

(a) *General rules.* (1) Except as provided in paragraph (a)(2) of this section, the employees of the Transmission Provider engaged in transmission system operations must function independently of its employees, or the employees of any of its affiliates, who engage in Wholesale Merchant Functions.

(2) Notwithstanding any other provisions in this section, in emergency circumstances affecting system reliability, Transmission Providers may take whatever steps are necessary to keep the system in operation. Transmission Providers must report to the Commission and on the OASIS each emergency that resulted in any deviation from the standards of conduct, within 24 hours of such deviation.

(b) *Rules governing employee conduct.* (1) *Prohibitions.* Any employee of the Transmission Provider, or any employee of an affiliate, engaged in wholesale merchant functions is prohibited from:

(i) Conducting transmission system operations or reliability functions; and

(ii) Having access to the system control center or similar facilities used for transmission operations or reliability functions that differs in any way from the access available to other open access Transmission Customers.

(2) *Transfers.* Employees engaged in either wholesale merchant functions or transmission system operations or reliability functions are not precluded from transferring between such functions as long as such transfer is not used as a means to circumvent the standards of conduct of this section. Notices of any employee transfer to or from transmission system operations or reliability functions must be posted on the OASIS as provided in § 37.6(g)(3). The information to be posted must include: the name of the transferring employee, the respective titles held while performing each function (*i.e.*, on behalf of the Transmission Provider and wholesale merchant or affiliate), and the effective date of the transfer. The information posted under this section must remain on the OASIS for 90 days.

(3) *Information access.* Any employee of the Transmission Provider, or of any of its affiliates, engaged in wholesale merchant functions:

(i) Shall have access to only that information available to the Transmission Provider's open access transmission customers (*i.e.*, the information posted on an OASIS), and must not have preferential access to any information about the Transmission Provider's transmission system that is not available to all users of an OASIS; and

(ii) Is prohibited from obtaining information about the Transmission Provider's transmission system (including information about available transmission capability, price, curtailments, ancillary services, and the like) through access to information not posted on the OASIS that is not otherwise also available to the general public without restriction, or through information through the OASIS that is not also publicly available to all OASIS users.

(4) *Disclosure.* A Transmission Provider is responsible for ensuring compliance with the following provisions:

[124] 5 U.S.C. § 804(2).

(i) Any employee of the Transmission Provider, or any employee of an affiliate, engaged in transmission system operations or reliability functions may not disclose to employees of the Transmission Provider, or any of its affiliates, engaged in wholesale merchant functions any information concerning the transmission system of the Transmission Provider or the transmission system of another (including information received from non-affiliates or information about available transmission capability, price, curtailments, ancillary services, etc.) through non-public communications conducted off the OASIS, through access to information not posted on the OASIS that is not at the same time available to the general public without restriction, or through information on the OASIS that is not at the same time publicly available to all OASIS users (such as E-mail).

(ii) If an employee of the Transmission Provider engaged in transmission system operations or reliability functions discloses information not posted on the OASIS in a manner contrary to the requirements of the standards of conduct, the Transmission Provider must immediately post such information on the OASIS.

(iii) A Transmission Provider may not share any market information, acquired from nonaffiliated Transmission Customers or potential nonaffiliated Transmission Customers, or developed in the course of responding to requests for transmission or ancillary service on the OASIS, with its own employees (or those of an affiliate) engaged in merchant functions, except to the limited extent information is required to be posted on the OASIS in response to a request for transmission service or ancillary services.

(5) *Implementing tariffs.* (i) Employees of the Transmission Provider engaged in transmission system operations or reliability functions must strictly enforce all tariff provisions relating to the sale or purchase of open access transmission service, if these provisions do not provide for the use of discretion.

(ii) Employees of the Transmission Provider engaged in transmission system operations must apply all tariff provisions relating to the sale or purchase of open access transmission service in a fair and impartial manner that treats all customers (including the public utility and any affiliate) in a non-discriminatory manner, if these provisions involve discretion.

(iii) The Transmission Provider must keep a log, available for Commission audit, detailing the circumstances and manner in which it exercised its discretion under any terms of the tariff.

(iv) The Transmission Provider may not, through its tariffs or otherwise, give preference to wholesale purchases or sales made on behalf of its own power customers, or those of an affiliate, over the interests of any other wholesale customer in matters relating to the sale or purchase of transmission service (including issues of price, curtailments, scheduling, priority, ancillary services, etc.).

(v) If the Transmission Provider offers a discount on purchases of transmission service made on behalf of its own power customers or those of any affiliate, then, at the same time, it must post on the OASIS an offer to provide the same discount to all Transmission Customers on the same path and on all unconstrained transmission paths.

(vi) If the Transmission Provider offers a rate discount on ancillary services to an affiliate, or attributes a discounted ancillary service rate to its own transactions, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all eligible customers.

(6) *Books and records.* A Transmission Provider must maintain its books of account and records (as prescribed under parts 101 and 125 of this chapter) separately from those of its affiliates and these must be available for Commission inspection.

(c) *Maintenance of written procedures.* The Transmission Provider must maintain in a public place, and file with the Commission, current written procedures implementing the standards of conduct in such detail as will enable customers and the Commission to determine that the Transmission Provider is in compliance with the requirements of this section.

§ 37.5 Obligations of Transmission Providers and Responsible Parties.

(a) Each Transmission Provider is required to provide for the operation of an OASIS, either individually or jointly with other Transmission Providers, in accordance with the requirements of this Part. The Transmission Provider may delegate this responsibility to a Responsible Party such as another Transmission Provider, an Independent System Operator, a Regional Transmission Group, or a Regional Reliability Council.

(b) A Responsible Party must:

(1) Provide access to an OASIS providing standardized information relevant to the availability of transmission capacity, prices, and other information (as described in this part) pertaining to the transmission system for which it is responsible; and

(2) Shall operate the OASIS in compliance with the standardized procedures and protocols found in OASIS Standards and Communication Protocols, which can be obtained from the Public Reference and Files Maintenance Branch, Room 2A, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

(c) Transmission Providers must provide ''read only'' access to the OASIS to Commission staff and the staffs of State regulatory authorities, at no cost, after such staff members have complied with the requisite registration procedures.

§ 37.6 Information to be posted on an OASIS.

(a) The information posted on the OASIS must be in such detail as to allow Transmission Customers to:

(1) Make requests for transmission services offered by Transmission Providers, Resellers and other providers of ancillary services;

(2) View and download in standard formats, using standard protocols, information regarding the transmission system necessary to enable prudent business decision making;

(3) Post, view, upload and download information regarding available products and desired services;

(4) Clearly identify the degree to which their transmission service requests or schedules were denied or interrupted; and

(5) Obtain access, in electronic format, to information to support available transmission capability calculations and historical transmission service requests and schedules for various audit purposes.

(b) *Posting transmission capability.* The transmission capability that is expected to be available on the Transmission Provider's system (ATC) and the total transmission capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

(1) *Definitions.* For purposes of this section the terms listed below have the following meanings:

(i) *Posted path* means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an

hour includes any part of an hour during which service was denied, curtailed or interrupted.

(ii) *Constrained posted path* means any posted path having an ATC less than or equal to 25 percent of TTC at any time during the preceding 168 hours or for which ATC has been calculated to be less than or equal to 25 percent of TTC for any period during the current hour or the next 168 hours.

(iii) *Unconstrained posted path* means any posted path not determined to be a constrained posted path.

(2) *Calculation methods, availability of information, and requests.* (i) Information used to calculate any posting of ATC and TTC must be dated and time-stamped and all calculations shall be performed according to consistently applied methodologies referenced in the Transmission Provider's transmission tariff and shall be based on current industry practices, standards and criteria.

(ii) On request, the Responsible Party must make all data used to calculate ATC and TTC for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (*e.g.*, thermal, voltage, stability)) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. This information is to be retained for six months after the applicable posting period.

(iii) System planning studies or specific network impact studies performed for customers to determine network impacts are to be made publicly available in electronic form on request and a list of such studies shall be posted on the OASIS. A study is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. These studies are to be retained for two years.

(3) *Posting.* The ATC and TTC for all Posted Paths must be posted in megawatts by specific direction and in the manner prescribed in this subsection.

(i) *Constrained posted paths*—(A) *For Firm ATC and TTC.* (*1*) The posting shall show ATC and TTC for a 30-day period. For this period postings shall be: by the hour, for the current hour and the 168 hours next following; and thereafter, by the day. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC and TTC will be posted daily for each period.

(*2*) Postings shall also be made by the month, showing for the current month and the 12 months next following.

(*3*) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following to the end of the planning horizon but not to exceed 10 years.

(B) *For Non-Firm ATC and TTC.* The posting shall show ATC and TTC for a 30-day period by the hour and days prescribed under paragraph (b)(3)(i)(A)(*1*) of this section and, if so requested, by the month and year as prescribed under paragraph (b)(3)(i)(A) (*2*) and (*3*) of this section.

(C) *Updating Posted Information for Constrained Paths.*

(*1*) The capability posted under paragraphs (b)(3)(i) (A) and (B) of this section must be updated when transactions are reserved or service ends or whenever the TTC estimate for the Path changes by more than 10 percent.

(*2*) All updating of hourly information shall be made on the hour.

(ii) *Unconstrained Posted Paths.* (A) Postings of ATC and TTC shall be by the day, showing for the current day and the next six days following and thereafter, by the month for the 12 months next following. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC and TTC will be posted for the current day and the next six days following for each period. These postings are to be updated whenever the ATC changes by more than 20 percent of the Path's TTC.

(B) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following until the end of the planning horizon but not to exceed 10 years.

(c) *Posting Transmission Service Products and Prices.* (1) Transmission Providers must post prices and a summary of the terms and conditions associated with all transmission products offered to Transmission Customers.

(2) Transmission Providers must provide a downloadable file of their complete tariffs in the same electronic format as the tariff that is filed with the Commission.

(3) A Transmission Provider, within 24 hours of agreeing to sell transmission service to a non-affiliate at a discount (as measured from when ATC must be adjusted in response to the transaction), must post on the OASIS (and make available for download) information describing the transaction (including price, quantity, and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of the audit log required in § 37.7. With respect to any discount offered to its own power customers or its affiliates, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all Transmission Customers on the same path and on all unconstrained transmission paths.

(4) Customers choosing to use the OASIS to offer for resale transmission capacity they have purchased must post relevant information to the same OASIS as used by the one from whom the Reseller purchased the transmission capacity. This information must be posted on the same display page, using the same tables, as similar capability being sold by the Transmission Provider, and the information must be contained in the same downloadable files as the Transmission Provider's own available capability. A customer reselling transmission capacity without the use of an OASIS must, nevertheless, inform the original Transmission Provider of the transaction within the time limits prescribed by the ''Sale or Assignment of Transmission Service'' section of the *pro forma* tariff.

(d) *Posting Ancillary Service Offerings and Prices.* (1) Any ancillary service required to be provided or offered under the *pro forma* tariff prescribed by part 35 of this chapter must be posted with the price of that service.

(2) A Transmission Provider, within 24 hours of agreeing to sell an ancillary service to a non-affiliate at a discount, must post on the OASIS (and make available for download) information describing the transaction (including price, quantity, and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of the audit log required in § 37.7. As to discounts for ancillary services, if a Transmission Provider offers a rate discount to an affiliate, or attributes a discounted ancillary service rate to its own transactions, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all eligible customers.

(3) Any other interconnected operations service offered by the Transmission Provider may be posted, with the price for that service.

(4) Any entity offering an ancillary service shall have the right to post the offering of that service on the OASIS if the service is one required to be offered by the Transmission Provider under the *pro forma* tariff prescribed by part 35 of this chapter. Any entity may also post any other interconnected operations service voluntarily offered by the Transmission Provider. Postings by customers and third parties must be on the same page, and in the same format, as postings of the Transmission Provider.

(e) *Posting Specific Transmission Service Requests and Responses.*

(1) *General rules.* (i) All requests for transmission service offered by Transmission Providers under the *pro forma* tariff must be made on the OASIS. Requests for transmission service, and the responses to such requests, must be conducted in accordance with the Transmission Provider's tariff, the Federal Power Act, and Commission regulations.

(ii) In processing a request for transmission or ancillary service, the Responsible Party shall post the following information: the date and time when the request is made, its place in any queue, the status of that request, and the result (accepted, denied, withdrawn).

(iii) The identity of the parties will be masked—if requested—during the negotiating period and for 30 days from the date when the request was accepted, denied or withdrawn.

(2) *Posting when a request for transmission service is denied.* (i) When a request for service is denied, the Responsible Party must provide the reason for that denial as part of any response to the request.

(ii) Information to support the reason for the denial, including the operating status of relevant facilities, must be maintained for 60 days and provided, upon request, to the potential Transmission Customer.

(iii) Any offer to adjust operation of the Transmission Provider's System to accommodate the denied request must be posted and made available to all Transmission Customers at the same time.

(3) *Posting when a transaction is curtailed or interrupted.*

(i) When any transaction is curtailed or interrupted, the curtailment or interruption must be posted (with the identities of the parties masked as required in § 37.6(e)(1)(iii)) and must state the reason why the transaction could not be continued or completed.

(ii) Information to support any such curtailment or interruption, including the operating status of the facilities involved in the constraint or interruption, must be maintained for 60 days and provided, upon request, to the curtailed or interrupted customer.

(iii) Any offer to adjust the operation of the Transmission Provider's system to restore a curtailed or interrupted transaction must be posted and made available to all curtailed and interrupted Transmission Customers at the same time.

(f) *Posting Transmission Service Schedules Information.* Information on transmission service schedules must be recorded by the entity scheduling the transmission service and must be available on the OASIS for download. Transmission service schedules must be posted no later than seven calendar days from the start of the transmission service.

(g) *Posting Other Transmission-Related Communications.* (1) The posting of other communications related to transmission services must be provided for by the Responsible Party. These communications may include ''want ads'' and ''other communications'' (such as using the OASIS as a Transmission-related conference space or to provide transmission-related messaging services between OASIS users). Such postings carry no obligation to respond on the part of any market participant.

(2) The Responsible Party is responsible for posting other transmission-related communications in conformance with the instructions provided by the third party on whose behalf the communication is posted. It is the responsibility of the third party requesting such a posting to ensure the accuracy of the information to be posted.

(3) Notices of transfers of personnel shall be posted as described in § 37.4(b)(2).

§ 37.7 Auditing Transmission Service Information.

(a) All OASIS database transactions, except other transmission-related communications provided for under § 37.6(g)(2), must be stored, dated, and time stamped.

(b) Audit data must remain available for download on the OASIS for 90 days. The audit data are to be retained and made available upon request for three years from the date when they are first posted.

§ 37.8 Implementation schedule for OASIS requirements; phases.

Each Transmission Provider must develop or participate in an OASIS that meets the requirements of this part and that is in operation by November 1, 1996. Each Transmission Provider must be in compliance with the standards of conduct prescribed in § 37.4 by November 1, 1996.

[NOTE: This attachment will not appear in the Code of Federal Regulations.]

ATTACHMENT 1.—LIST OF COMMENTERS TO RIN NOPR

Number	Commenter name	Abbreviation
1	ABB Systems Control	(ABB)
2	Allegheny Power Service Corporation	(Allegheny)
3	American Electric Power	(AEP)
4	American Public Power Association	(APPA)
5	City of Anaheim, CA	(Anaheim)
6	Arizona Public Service Company	(Arizona)
7	Bangor Hydro-Electric Company	(Bangor)
8	Basin Electric Power Cooperative	(Basin EC)
9	Bonneville Power Administration	(BPA)
10	California PUC	(CA Com)
11	Carolina Power & Light Company	(Carolina P&L)
12	Central Hudson Gas & Electric Corp	(Central Hudson)
13	Central Illinois Public Service Company	(Central Illinois Public Service)
14	CINergy Corporation	(CINergy)
15	Coalition for a Competitive Electric Market	(CCEM)
16	Colorado Springs Utilities	(CSU)
17	Commonwealth Edison Company	(Com Ed)
18	Consolidated Edison Company	(ConEd)

[NOTE: This attachment will not appear in the Code of Federal Regulations.]

ATTACHMENT 1.—LIST OF COMMENTERS TO RIN NOPR

Number	Commenter name	Abbreviation
19	Consumers Power Company	(Consumers Power)
20	Continental Power Exchange	(Continental Power Exchange)
21	CSW Companies	(CSW)
22	Dayton Power and Light Company	(Dayton P&L)
23	Detroit Edison Company	(Detroit Edison)
24	Duke Power Company	(Duke)
25	Edison Electric Institute	(EEI)
26	El Paso Electric Company	(El Paso)
27	Electric Generation Association	(EGA)
28	Electric Reliability Council of Texas	(ERCOT)
29	Entergy Services, Inc	(Entergy)
30	Florida Electric Power Coordinating Group	(Florida CG)
31	Florida Power Corporation	(Florida Power Corp)
32	Florida PSC	(FL Com)
33	Fuel Managers Association	(Fuel Managers)
34	''How'' Industry Working Group (EPRI)	(How Group)
35	Idaho Power Company	(Idaho)
36	Indiana Utility Regulatory Commission	(IN Com)
37	Indianapolis Power & Light Company	(Indianapolis P&L)
38	Klein, Stanley A	(Klein)
39	Long Island Lighting Company	(LILCO)
40	Madison Gas and Electric Company	(Madison G&E)
41	Maine Public Service Company	(Maine Public Service)
42	MidAmerican Energy Company	(MidAmerican)
43	Mid-Continent Area Power Pool	(MAPP)
44	Minnesota Power & Light Company	(Minnesota P&L)
45	Missouri Public Service Commission	(MO & AK Com's)
46	Montana Power Company	(Montana Power)
47	National Association of Regulatory Utility Commissioners	(NARUC)
48	National Independent Energy Producers	(NIEP)
49	National Rural Electric Cooperative Association	(NRECA)
50	Nebraska Public Power District	(NE Public Power District)
51	New England Power Pool	(NEPOOL)
52	New York Mercantile Exchange	(NYMEX)
53	New York Power Pool	(NYPP)
54	New York State Electric & Gas Corp	(NYSEG)
55	New York State PSC	(NY Com)
56	NorAm Energy Services, Inc	(NorAm)
57	North American Electric Reliability Council	(NERC)
58	North Carolina Electric Membership Corp	(NCEMC)
59	Northeast Texas Electric Cooperative, Inc	(NTEC)
60	Northeast Utilities	(NU)
61	Northern States Power Companies	(NSP)
62	Nucor Corporation	(Nucor)
63	Oak Ridge National Lab, Energy Division	(Oak Ridge)
64	Ohio Edison Company	(Ohio Edison)
65	Ohio PUC	(Ohio Com)
66	Oklahoma Corporation Commission	(OK Com)
67	Oklahoma Gas & Electric	(Oklahoma G&E)
68	Omaha Public Power District	(Omaha PPD)
69	Ontario Hydro	(Ontario Hydro)
70	Orange and Rockland Utilities, Inc	(Orange & Rockland)
71	Oregon Trail Electric Consumers Cooperative	(Oregon EC)
72	Otter Tail Power Company	(Otter Tail)
73	Pacific Gas and Electric Company	(PG&E)
74	PacifiCorp	(PacifiCorp)
75	Pennsylvania—New Jersey—Maryland Power Pool	(PJM)
76	Pennsylvania Public Utility Commission	(PA Com)
77	Public Generating Pool	(Public Generating Pool)
78	Public Service Company of New Mexico	(PSNM)
79	Sacramento Municipal Utility District	(SMUD)
80	Salt River Project	(Salt River)
81	San Diego Gas & Electric Company	(San Diego G&E)
82	Seattle City Light	(Seattle)
83	Services-Oriented Open Network Technologies, Inc.	(SONETECH)
84	Sierra Pacific Power Company	(Sierra)
85	South Carolina Electric & Gas Company	(SCE&G)
86	South Carolina Public Service Authority	(SC Public Service Authority)
87	Southern California Edison Company	(SoCal Edison)
88	Southern Company Services, Inc	(Southern)
89	Southwest Transmission Dependent Utility Group	(Southwest TDU Group)

[NOTE: This attachment will not appear in the Code of Federal Regulations.]

ATTACHMENT 1.—LIST OF COMMENTERS TO RIN NOPR

Number	Commenter name	Abbreviation
90	Southwestern Public Service Company	(Southwestern)
91	Sunflower Electric Power Cooperative	(Sunflower)
92	City of Tallahassee, FL	(Tallahassee)
93	Tampa Electric Company	(Tampa)
94	Tennessee Valley Authority	(TVA)
95	Texas Utilities Electric Company	(Texas Utilities)
96	Transmission Access Policy Study Group	(TAPS)
97	Tucson Power Electric Power Company	(Tucson Power)
98	Union Electric Company	(Union Electric)
99	United Illuminating Company	(United Illuminating)
100	U.S. Department of Energy, Office of Energy Research	(DOE)
101	UTC, The Telecommunications Association	(UTC)
102	Virginia Electric and Power Company	(VEPCO)
103	Western Group	(Western Group)
104	Wisconsin Power & Light	(WP&L)

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[NOTE: This attachment will not appear in the Code of Federal Regulations.]

ATTACHMENT 2

Docket No. RM95-9

Form Approved
OMB No. 1902-0173
Expires February 28, 1999

FEDERAL ENERGY REGULATORY COMMISSION

STANDARDS

AND

COMMUNICATION PROTOCOLS

FOR

OPEN ACCESS SAME-TIME INFORMATION SYSTEM

(OASIS)

Version 1.0

(April 24, 1996)

The public burden for the development and initial operation of this information requirement is estimated to average 1,879 reporting hours and 418 record keeping hours per public utility. The estimate includes the time required to review and implement the standards, develop the necessary software, search existing data sources, gather and maintain the data, complete and review the information. Send comments regarding this burden estimate or any other aspect of this information requirement, including suggestions for reducing the burden, to each of the following:

Federal Energy Regulatory Commission
Attention: Michael Miller, Information Services Division
888 First Street, N.E.
Washington, DC 20426

Office of Management and Budget
Office of Information and Regulatory Affairs
Attention: Desk Officer for the Federal Energy Regulatory Commission
Washington, DC 20503

You shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

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GENERAL INFORMATION

I. Purpose

In Order No. 888 the Commission requires public utilities to provide comparable access to transmission services and transmission system information. Order No. 889 amends the Commission's regulations, by adding 18 CFR Section 37, to require utilities to provide information about the availability of transmission service on an Open Access Same-Time Information System (OASIS). This information will be provided both through displays and through standardized files that users can download to their own computers. Certain information will also be uploaded through standardized forms and files transmitted from customers' computers to the OASIS. The regulations require public utilities to comply with standardized procedures and communication protocols governing the means by which the information is made available. This document contains the standardized data sets that show the information that must be provided, standard operating procedures and the protocols for communication of that information.

II. Who Must Comply

All jurisdictional public utilities that are required to maintain an OASIS under Part 37 of the Commission's regulations must comply with these standards and communication protocols.

III. Implementation Date

Utilities must implement these standards and protocols by November 1, 1996.

IV. Development Of The Standards And Communication Protocols

The standards and communication protocols were developed by the electric utility industry through a working group facilitated by EPRI. This working group included representatives from all major segments of the electric utility industry, such as utilities and marketers, as well as other interested parties such as computer and software firms. The standards and communication protocols represent a broad agreement of the working group.

As the industry obtains experience with OASIS and the new operating environment created by Order No. 888, the standards and communication protocols will need to be revised. The Commission has requested the industry to continue to develop standards and identify necessary changes. The Commission will provide all

interested parties with notice and an opportunity for comment on proposed changes to this document.

V. OASIS STANDARDS AND COMMUNICATION PROTOCOLS

1. INTRODUCTION

1.1 DEFINITION OF TERMS

The following definitions are offered to clarify discussions of the OASIS in this document.

a. **Transmission Services Information (TS Information)** is transmission and ancillary services information which must be made available by public utilities on a non-discriminatory basis to meet the regulatory requirements of transmission open access.

b. **Open Access Same-Time Information System (OASIS)** comprises the computer systems and associated communications facilities that public utilities are required to provide for the purpose of making available to all transmission users comparable interactions with TS Information.

c. **Open Access Same-Time Information System Node (OASIS Node)** is a subsystem of the OASIS. It is one computer system in the (OASIS) that provides access to TS Information to a Transmission Customer.

d. **Transmission Provider (TP or Provider)** is the public utility (or its designated agent) that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce . (This is the same term as is used in Part 35.3)

e. **Transmission Customer (TC or Customer)** is any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. (This is the same term as is used in Part 35.3)

f. **Secondary Transmission Provider (ST, Reseller, or Secondary Provider)** is any Customer who offers to sell transmission capacity it has purchased. (This is the same as Reseller in Part 37)

g. **Transmission Services Information Provider (TSIP)** is a Transmission Provider or an agent to whom the Transmission Provider has delegated the responsibility of meeting any of the requirements of Part 37. (This is the same as Responsible Party in Part 37)

h. **Value-Added Transmission Services Information Provider (VTSIP)** is an entity who uses TS Information in the same manner as a Customer and provides value-added information services to its Customers.

2. NETWORK ARCHITECTURE REQUIREMENTS

2.1 ARCHITECTURE OF OASIS NODES

a. **Permit Use of Any OASIS Node Computers:** TSIPs shall be permitted to use any computer systems as a OASIS Node, so long as they meet the OASIS requirements.

b. **Permit Use of Any Customer Computers:** OASIS Nodes shall permit the use by Customers of any commonly available computer systems, as long as they support the required communication links to the Internet.

c. **Permit the Offering of Value-Added Services:** TSIPs are required, upon request, to provide their Customers the use of private network connections on a cost recovery basis. Additional services which are beyond the scope of the minimum OASIS requirements are also permitted. When provided, these private connections and additional services shall be offered on a fair and non-discriminatory basis to all Customers who might chose to use these services.

d. **Permit Use of Existing Communications Facilities:** In implementing the OASIS, the use of existing communications facilities shall be permitted. The use of OASIS communication facilities for the exchange of information beyond that required for open transmission access (e.g., transfer of system security or operations data between regional control centers) shall also be permitted, provided that such use does not negatively impact the exchange of open transmission access data and is consistent with the Standards of Conduct in Part 37.

e. **Single or Multiple Providers per Node:** A OASIS Node may support a single individual Primary Provider (plus any Secondary Providers) or may support many Providers.

2.2 INTERNET-BASED OASIS NETWORK

a. **Internet Compatibility:** All OASIS Nodes shall support the use of internet tools, internet directory services, and internet communication protocols necessary to support the Information Access requirements stated in Section 4.

b. **Connection through the public Internet:** Connection of OASIS Nodes to the public Internet is required so that Users may access them through Internet links. This connection shall be made through a firewall to improve security.

c. **Connection to a private internet network:** OASIS Nodes shall support private connections to any OASIS User (User) who requests such a connection. The TSIP is permitted to charge the User, based on cost, for these connections. The same internet tools shall be required for these private networks as are required for the public Internet. Private connections must be provided to all users on a fair and nondiscriminatory basis.

d. **Internet Communications Channel:** The OASIS Nodes shall utilize a communication channel to the Internet which is adequate to support the performance requirements given the number of Users subscribed to the Providers on the Node (see section 5.3).

2.3 COMMUNICATION STANDARDS REQUIRED

a. **Point-to-Point Protocol (PPP) and Internet Protocol Control Protocol (IPCP)** (reference RFCs 1331 and 1332) shall be supported for private internet network dial-up connections.

b. **Serial Line Internet Protocol (SLIP)** (reference RFC 1055) shall be supported for private internet network dial-up connections.

c. **Transport Control Protocol and Internet Protocol (TCP/IP)** shall be the only protocol set used between OASIS Nodes whenever they are directly interconnected, or for Users using private leased line internet network connections.

d. **Hyper Text Transport Protocol (HTTP)** shall be supported on the OASIS Node so that Users can use it to select information for viewing displays and for downloading and uploading files electronically.

e. **Internet Protocol Address:** All OASIS Nodes are required to use an IP address registered with the Internet Network Information Center (InterNIC), even if private connections are used.

2.4 INTERNET TOOL REQUIREMENTS

Support for the following specific internet tools is required, both for use over the public Internet as well as for any private connections between Users and OASIS Nodes:

a. **Hypertext Markup Language (HTML),** at least version 3, and optionally Secure Sockets Layer (SSL), shall be used by TSIPs as a standard tool for presenting information to Users.

b. **HTML Forms** shall be provided by the TSIPs for Customers to use to request purchases from a Provider. The activation of a form (sending a filled-out form to the Provider) shall be time-stamped and logged as part of the audit trail.

c. **Domain Name Service (DNS)** (ref. RFC 1034, 1035) shall be provided as a minimum by the TSIPs (or their Internet Service Provider) for the resolution of IP addresses to allow Users to navigate easily between OASIS Nodes.

d. **Simple Network Management Protocol (SNMP)** shall be supported to provide tools for operating and managing the network, if private interconnections between OASIS

Nodes are established.

e. **E-mail** shall be supported by the OASIS Node for exchanges between Providers and Customers, including the sending of attachments. The protocols supported shall include, as a minimum, the Simple Messaging Transfer Protocol (SMTP), POP, and MIME.

2.5 NAVIGATION AND INTERCONNECTIVITY BETWEEN OASIS NODES

a. **World Wide Web Browsers:** TSIPs shall permit Users to navigate using WWW browsers for accessing different sets of TS information from one Provider, or for getting to TS information from different Providers on the same OASIS Node. These navigation methods shall not favor User access to any Provider over another Provider, including Secondary Providers.

b. **Internet Interconnection across OASIS Nodes:** Navigation tools shall not only support navigation within the TSIP's Node, but also across interconnected OASIS Nodes. This navigation capability across interconnected Nodes shall, as a minimum, be possible through the public Internet.

3. INFORMATION ACCESS REQUIREMENTS

3.1 REGISTRATION AND LOGIN REQUIREMENTS

a. **Location of Providers:** To provide Users with the information necessary to access the desired Providers, publicly available documentation or menus shall list the OASIS Node addresses of all Primary, Secondary, and Value-Added Providers.

b. **Initial User Registration:** TSIPs shall require Users to register with a Provider before they are permitted to access the Provider's TS information. This registration shall require at least the following information:

- Company name
- Name of company OASIS Account Administrator
- Name of the individual user(s) within a company (each individual user is considered as a separate User with possibly different levels of authority)
- User password
- Supplemental information such as address, telephone number, fax number, and e-mail

c. **Initial Access Privileges:** Initial registration shall permit a User only the minimum Access Privileges. A User and a Provider shall mutually determine what access privilege the User is permitted: the TSIP shall set a User's Access Privilege as authorized by the Provider.

d. **User Login:** After registration, Users shall be required to login every time they establish a dial-up connection. If a direct, permanent connection has been established, Users shall be required to login initially or any time the connection is lost. Use of alternative forms of login and authentication using certificates and public key standards is acceptable.

e. **User Logout:** Users shall be automatically logged out any time they are disconnected. Users may logout voluntarily.

3.2 SERVICE LEVEL AGREEMENTS

a. **Service Level Agreements:** It is recognized that Users will have different requirements for frequency of access, performance, etc., based on their unique business needs. To accommodate these differing requirements, TSIPs shall be required to establish a "Service Level Agreement" with each User which specifies the terms and conditions for access to the information posted by the Providers. The default Service Level Agreement shall be Internet access with the OASIS Node meeting all minimum performance requirements.

3.3 ACCESS TO INFORMATION

a. **Text Display:** TSIPs shall format all TS information as plain or HTML 3.0 text such that it may be viewed and read directly by Users without requiring them to download it. This text shall be in clear English as much as possible, with the definitions of any mnemonics or abbreviations available on-line. The templates for displaying the text are described in Section 4.3.

b. **Read-Only Access to TS Information:** For security reasons, Users shall have read-only access to the TS information. They shall not be permitted to enter any information except where explicitly allowed, such as on transaction request forms.

c. **Downloading Capability:** Users shall be able to download from a OASIS Node the TS information in electronic format as a file. The rules for formatting of this data are described in section 4.4.

d. **On-Line Data Entry on Forms:** Customers shall be permitted to fill out on-line the Service Request forms supplied by the TSIPs on the OASIS Nodes, for requesting the purchase of services and for posting of products for sale (by Customers who are resellers). Customers shall also be permitted to fill-out and post Want-Ads.

e. **Uploading Capability:** Customers shall be able to upload to OASIS Nodes the filled-out forms. TSIPs shall ensure that these uploaded forms are handled identically to forms filled out on-line. TSIPs shall provide Forms that support the "file" input type available in HTML 3.0. This capability shall permit a Customer to upload a file (or

files) using standard Web browsers by providing an input space to specify a file stored on the Customer's hard disk.

f. **Selection of TS Information:** Users shall be able to dynamically select the TS information they want to view and/or download. This selection shall be, as a minimum, through navigation to text displays, the use of pull-down menus to select information for display, data entry into forms for initiating queries, and the selection of files to download via menus.

3.4 PROVIDER UPDATING REQUIREMENTS

TO BE COMPLETED BY INDUSTRY

3.5 ACCESS TO CHANGED INFORMATION

a. **General Message & Log:** TSIPs shall post a general message and log that may be read by Users. The message shall state that the Provider has updated some information, and shall contain (or point to) a reverse chronological log of those changes. The User may use the manual or automatic refresh capability to see the message.

b. **TSIP Notification Design Responsibilities:** The TSIP shall avoid a design that could cause serious performance problems by necessitating frequent requests for information from many Customers.

3.6 SERVICE REQUEST TRANSACTION SUPPORT

The requirements for supporting Service Request transactions are as follows:

a. **Basic Service Request Transaction Support:** Providers shall support basic Service Request transaction requests from the Customer. All forms shall be formatted according to the Service Request templates described in Section 4. Specifically, the following four types of transactions shall be supported as a minimum:

- A Customer issues a Service Request to a Provider, either by data entry on an on-line form or by uploading a filled-out form.
- The TSIP posts the receipt of the Service Request to the Customer.
- The Provider responds by posting the Service Request Status of the Customer's Service Request each time it changes. The changed status includes: received by the Provider, accepted by seller, accepted by customer, confirmed for scheduling, withdrawn, or refused / rejected.
- The Provider issues an acknowledgment of his acceptance or denies the Service Request.
- The Customer issues an acknowledgment of his acceptance or withdraws the

Service Request.

- A Customer who wishes to resell transmission rights shall issue a request to the TSIP for a product posting and then becomes a seller of transmission rights.

4. INTERFACE REQUIREMENTS

4.1 INFORMATION MODEL CONCEPTS

4.1.1 ASCII-Based Information Model

a. **ASCII-Based OASIS Templates:** For displaying information to Users, TSIPs shall use the specified OASIS Templates. These Templates define the information which, as a minimum, must be presented to Users, both in the form of graphical displays and as downloaded files, whenever they access the Template. Users shall be able to request Template information using the request-response data flows (Query Variables for use with HTTP) that are defined in Appendix B. Responses shall contain the same Query Variables containing the results of the query. The OASIS Templates are described in section 4.3. The Data Element Dictionary which defines the data elements in the OASIS Templates is provided in Appendix A.

   Additional information may be presented in a display or a file at the discretion of the TSIP. However, no User shall be obligated or expected to recognize or use this additional information. As stated above, although the minimal ***contents*** of the displays are precisely defined, the actual graphical display ***formats*** of the TS information are beyond the scope of the OASIS requirements.

b. **ASCII-Based OASIS File Structures:** For uploading requests from and downloading information to Users, TSIPs shall use specific file structures that are defined for OASIS Template information (see section 4.4). These file structures are based on the use of headers which contain the Query Variable information, including the name of the OASIS Template. These headers thus determine the contents and the format of the data that follows.

4.2 OASIS NODE CONVENTIONS AND STRUCTURES

4.2.1 OASIS Node Naming Requirements

The following are the OASIS Node naming requirements:

a. **Node Naming Convention:** In order to provide a consistent method for locating a OASIS Node, the standard Internet naming convention shall be used. All OASIS Node names shall be unique, and shall be registered to the OASIS Management Organization at the web site http://www.tsin.com. OASIS Node names shall be stored in a DNS name directory, which shall be accessible by Customers as an HTML page.

b. **URL Structure:** The OASIS Node naming conventions shall use standard URL structures.

c. **OASIS Node Home Directory:** The home directory name on a OASIS Node shall be "OASIS" to identify that the directory is related to the OASIS. The name of each Primary Provider and Secondary Provider with shall be listed under "OASIS" with a "hot-link", so that Users can navigate directly to Provider Home Pages. Common Gateway Interface (CGI) scripts shall be located in the directory "cgi" as follows:

//(OASIS Node name)/OASIS/(Transmission Provider)/cgi/(cgi script name)

Where:

(OASIS Node name) is the World Wide Web URL address of the OASIS Information Provider.
Transmission Provider is the 4 character acronym of the transmission provider
(cgi script name) is (register ¦ (template name)) (?search)
Where:
register is the name of the cgi script program to register a user
(template name) is name of the template cgi script for the template of data being requested, see Appendix B, Query Variables.
(?search) a list of query variable with their settings

Example:

To request the hourly schedule template at WXYZ Co.

http://www.wxyz.com/oasis/wxyz/cgi/scheduledatc
?TEMPLATE=scheduledatc&VER=1&FMT=html
&DATETIMETZ=19960412040000PD&PROVIDER=wxyz ...

4.2.2 Data Element Dictionary

The following are the requirements for the Data Element Dictionary:

a. **Definition of OASIS Information Elements:** All OASIS Information elements shall be defined in the Data Element Dictionary which will be stored in the OASIS Node directory:

http://(OASIS Node Name)/OASIS/(Transmission Provider)/(datadic.html ¦ datadict.txt).
Where:
datadic.html is the HTML version of the data element dictionary
datadic.txt is the ASCII text version of the data element dictionary

The global Data Dictionary is defined in Appendix A.

The local data element names, such as Path Codes, may be unique within the Primary Provider's territory, while universally accessible data element names shall be globally unique. In posting OASIS information, TSIPs shall use only the names listed in the

Data Element Dictionary.

Each entry in the Data Element Dictionary shall contain as a minimum:

- Unique name of the data element
- Description of the data element
- Formats for all primitive data elements shall include:
  - Character string (ASCII), Floating point, integer, Boolean, universal time format, registered object definition, etc.
  - Length of field
- Units
- Lists of valid values that the data element could assume, limits on numerical values, or other validation criteria.
- Definition of the data element

4.2.3 General Rules for OASIS Templates

Section 4.3 lists the set of OASIS Templates. These OASIS Templates are intended to be used precisely as shown for download and upload of data. For on-line display, all relevant information must be provided but flexibility is permitted as to how the data are displayed. The construction of the OASIS Templates shall follow the rules described below:

a. **Unique OASIS Template Name:** Each type of OASIS Template shall be identified with a unique name which shall be displayed to the User whenever the OASIS Template is accessed.

b. **Source Information:** Each OASIS Template shall identify the source of its information by including or linking to the name of the Primary Provider, the Secondary Provider, or the Customer who provided the information.

c. **Time Stamp:** Each OASIS Template shall include a timestamp indicating when it was created or last updated.

d. **Column Headings:** OASIS Template column headings shall define the elementary Data Element Dictionary entries for the data values. The order of the column headings shall define the order that the values are presented. Within a table, the ordering of some column headings may be selected by Users from pull-down menus. For tables with selectable columns, the number of columns displayed or selected for download shall be determined by entry into a specified field.

e. **Rows:** The table rows below the column headings shall represent the data being presented.

f. **Row Wrap:** If the width of tables is larger than can be displayed in readable size on

a single screen, the rows shall either wrap on the screen or shall be accessible through horizontal scrolling.

g. **Documentation:** OASIS Information shall be in non-cryptic English, with all mnemonics defined in a glossary of terms. TSIPs shall provide on-line descriptions and help screens to assist Users understanding the displayed information. Documentation of all formats, contents, and mnemonics shall be available both as displays and as files which can be downloaded electronically.

- HTML "Hot-Links" or other pointer mechanisms may be provided for column headings in OASIS Templates which permit the User to access documentation describing the meaning, type, and format of the data in the column.
- HTML "Hot-Links" or other pointer mechanisms may be provided for data in the OASIS Templates to explanations, comments, constraints, and other notes.
- In order to meet the "User-Friendly" goal and permit the flexibility of the OASIS to expand to meet new requirements, the OASIS Templates shall be as self-descriptive as possible.

4.2.4 Display Request and Response Procedures

4.2.4.1 Display Request

A request for the display of the information in a OASIS Template shall consist of the following minimal input (either through direct data entry or through selection procedures):

TEMPLATE=(template name)

Additional Query Variables may be included to specify non-default data, either through direct data entry or through selection procedures. These additional Query Variables shall be prefixed with an ampersand (&), suffixed with an equal sign (=), and followed by the appropriate parameters.

If repeated values are given for a Query Variable, the variable name will be suffixed with a digit starting with "1" and increasing by one for each repeated variable, for example:

&PATH1=ABC-XYZ &PATH2=ABC-RST

4.2.4.2 Display Response

The information in the OASIS Template requested shall be presented as a display, using the display formats defined by the TSIP.

4.2.5 File Request, File Download Response, and Form Upload Rules and Procedures

4.2.5.1 File Request Rules and Procedure

A request to download a file of the information in a OASIS Template to a User site shall consist of the following minimal input (either through direct data entry, through selection procedures on a display, or through an uploaded computer file):

TEMPLATE=(*template name*)
&VER=(*nn.n*)
&FMT=(aaaa)
$DTZ= (nnnnnnnnnnnnnnaa)
$PROVIDER=(aaaa)

Additional Query Variables may follow to specify specific data; otherwise default data will be assumed. These additional Query Variables shall be prefixed with an ampersand (&), suffixed with an equal sign (=), and followed by the appropriate parameters.

If repeated values are given for a Query Variable, the variable name will be suffixed with a digit starting with "1" and increasing by one for each repeated variable, for example:

&PATH1=ABC-XYZ &PATH2=ABC-RST

4.2.5.2 File Download Response Rules and Procedures

The response to a request for the download of Template information into file at the User site shall conform to the following rules:

a. **Download ASCII Delimited Files:** Users shall always be able to download all OASIS Template information in ASCII with no special embedded codes.

   Query Variables shall be used to define what data is being downloaded. Each Query Variable (containing the response to the query) shall be followed by an equals sign (=) and the parameters associated with the variable.

   Each record shall be separated by a carriage return plus line feed (↵). The fields within a record shall be delimited by a comma (,). Text fields shall be enclosed with double quotes (").

b. **Data Compression:** Data compression of downloadable files shall be supported, using ZIP compression methods.

c. **Non-ASCII Formats:** Formats in addition to ASCII may be used (at the TSIP's option). If formats other than ASCII are available for downloading or uploading

specific data elements, these formats shall be indicated in the Data Element Dictionary for those data elements.

d. **Partial OASIS Template Download**: TSIPs shall either divide large OASIS Templates into separate files for downloading or shall permit the User to select which rows of a OASIS Template they wish to download.

Every download file for a OASIS Template shall contain the following records in the indicated order.

The following 6 records shall always precede the Template information:

REQUEST_STATUS=*nnn*↵
VERSION=*nn.n*↵
DATETIMETZ=*nnnnnnnnnnnnnnaa*↵
PRIMARY_PROVIDER=*aaaaaaaaaaaaaaaaaaaaaaaaaa*↵
DATA_ROWS=*nnn*↵
COLUMN_HEADERS=*aaaa.....aaaaaa*↵

The DATA_ROWS record contains the number of data records following the COLUMN_HEADERS. The COLUMN_HEADERS record contains a column for each field that is required in the Template, in the order shown in the Template.

The Template information then follows as records which correspond one-to-one with the column headings. The order of the records shall be that a column only changes its value after all columns to the right of it have changed their values. In other words, the rightmost column varies first, then the second rightmost, on back to the leftmost column which varies only after all columns to the right have varied.

4.2.5.3 Form Upload Rules and Procedures

a. **Upload using HTTP Protocol:** Customers and Providers shall be able to upload OASIS Templates using the file request format of section 4.2.5.1.

b. **Upload ASCII Delimited Files:** Customers and Providers shall be able to upload OASIS Templates in ASCII with no special embedded codes.
Query Variables shall be used to define what data is being uploaded. Each Query Variable shall be followed by an equals sign (=) and the parameters associated with the variable.

Each record shall be separated by a carriage return plus line feed (↵). The fields within a record shall be delimited by a comma (,). Text fields shall be enclosed with double quotes (").

Every ASCII delimited upload file reflecting an input OASIS Template (as opposed to a file requesting Template information) shall contain the following records in the indicated order.

TEMPLATE=(template name)↵ (If template CGI procedure is called then this record is optional)
VERSION=*nn.n*↵
OUTPUT_FORMAT=*aaaa*↵
DATETIMETZ=*nnnnnnnnnnnnnnaa*↵
PRIMARY_PROVIDER=*aaaaaaaaaaaaaaaaaaaaaaaaaa*↵
DATA_ROWS=*nnn*↵
COLUMN_HEADERS=*aaaa.....aaaaaa*↵

The DATA_ROWS record contains the number of data records following the COLUMN_HEADERS.

The COLUMN_HEADERS record contains a column for each field that is required in the Template, in the order shown in the Template. The Template information then follows as records which correspond one-to-one with the column headings.

c. **Data Compression:** Data compression of large uploaded files shall be supported, using ZIP compression methods.

d. **Default User Directory:** The default customer directory for upload of files shall be /OASIS/(Provider)/upload
Where: Provider is the 4 character acronym of the Primary Provider.

4.3 TEMPLATE DESCRIPTIONS

The following OASIS Templates are required as a minimum. The definitions of the data elements are listed in the Data Dictionary in Appendix A. The definitions of the Query Variables are listed in the Query Variable Dictionary in Appendix B.

TSIPs must provide a more detailed supplemental definition of the terms Point of Receipt (POR) and Point of Delivery (POD), clarifying how the terms are being used. If POR and POD are not used, then Path Name must include directionality.

Most of the Templates represent response information, sent from the OASIS Node to the Customer. Some, as noted in their descriptions, are input information, sent from the Customer to the OASIS Node.

4.3.1 Summary System Information Templates

The Summary System Information Templates provide information on a specific path with ATC being offered by one or more Providers (Primary and Secondary Providers).

a. **Summary Path Hourly ATC Template (sumpathhouratc)**
- PROVIDERS (all PROVIDERS supplying CAPACITY for Path)
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- INTERFACE_TYPE
- COMMENTS
- DTMMTZ (Date and Time Available)
- CAPACITY
- CAPACITY_TYPE

b. **Summary Path Daily ATC Template (sumpathdayatc)**
- PROVIDERS (all PROVIDERS supplying CAPACITY for Path)
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- INTERFACE_TYPE
- COMMENTS
- DTMMTZ (Date and Time Available)
- CAPACITY
- CAPACITY_TYPE

c. **Summary Monthly ATC Template (sumpathmonthatc)**
- PROVIDERS (all PROVIDERS supplying CAPACITY for Path)
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- INTERFACE_TYPE
- COMMENTS
- DTMMTZ (Date and Time Available)
- CAPACITY
- CAPACITY_TYPE

d. **Summary Yearly ATC Template (sumpathyearatc)**
- PROVIDERS (all PROVIDERS supplying CAPACITY for Path)
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- INTERFACE_TYPE

- COMMENTS
- DTMMTZ (Date and Time Available)
- CAPACITY
- CAPACITY_TYPE

4.3.2 Provider System Information Templates

The OASIS Templates which display Provider TS Information shall provide the following information. Depending upon the Query Variables, the information will be provided with Providers per Path or Paths per Provider or other combinations:

a. **Hourly Capacity Available for Purchase** (houratc)is used to display the hourly ATC that is available for sale by a Primary Provider or Reseller for one or more paths.
   - PRIMARY_PROVIDER
   - PATH_NAME
   - POINT_OF_RECEIPT
   - POINT_OF_DELIVERY
   - BEGDATETZ
   - ENDDATETZ
   - SELLER_NAME
   - INTERFACE_TYPE
   - ANCILLARY_SERVICES_REQUIREMENTS
   - COMMENTS
   - TIME_OF_LAST_UPDATE
   - DTMMTZ (Date and Time Available)
   - CAPACITY
   - CAPACITY_TYPE
   - PRICE
   - PRICE_UNITS

b. **Daily Capacity Available for Purchase** (dayatc) is used to display the daily ATC that is available for sale by a Primary or Secondary Provider.
   - PRIMARY_PROVIDER
   - PATH_NAME
   - POINT_OF_RECEIPT
   - POINT_OF_DELIVERY
   - BEGDATETZ
   - ENDDATETZ
   - SELLER_NAME
   - INTERFACE_TYPE
   - ANCILLARY_SERVICES_REQUIREMENTS
   - COMMENTS
   - TIME_OF_LAST_UPDATE
   - DTMMTZ (Date and Time Available)

- CAPACITY
- CAPACITY_TYPE
- PRICE
- PRICE_UNITS

c. **Monthly Capacity Available for Purchase** (monthatc) is used to display the monthly ATC that is available for sale.
- PRIMARY_PROVIDER
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- BEGDATETZ
- ENDDATETZ
- SELLER_NAME
- INTERFACE_TYPE
- ANCILLARY_SERVICES_REQUIREMENTS
- COMMENTS
- TIME_OF_LAST_UPDATE
- DTMMTZ (Date and Time Available)
- CAPACITY
- CAPACITY_TYPE
- PRICE
- PRICE_UNITS

d. **Yearly Capacity Available for Purchase** (yearatc) is used to display the yearly ATC that is available for sale. (Optional)
- PRIMARY_PROVIDER
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- BEGDATETZ and ENDDATETZ
- SELLER_NAME
- INTERFACE_TYPE
- ANCILLARY_SERVICES_REQUIREMENTS
- COMMENTS
- TIME_OF_LAST_UPDATE
- DTMMTZ (Date and Time Available)
- CAPACITY
- CAPACITY_TYPE
- PRICE
- PRICE_UNITS

e. **Hourly Schedule** (scheduledatc) is used to display a Provider's scheduled transmission capacity usage.

- PRIMARY_PROVIDER
- PATH_NAME(S)
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- CURTAILMENT_PRIORITY
- SOURCE
- SINK
- ASSIGNMENT_REF
- INTERFACE_TYPE
- CUSTOMER_REQUEST_IDENTITY
- DEAL_REFERENCE
- COMMENTS
- TIME_OF_LAST_UPDATE
- DTMMTZ (Date and Time Available)
- CAPACITY
- CAPACITY_TYPE
- PRICE
- PRICE_UNITS

4.3.3 Secondary Provider (Reseller) Posting Templates

Sellers may aggregate portions of several previous purchases to create a new service, if this capability is provided by the Transmission Services Information Provider.
Secondary Providers shall use the following templates for providing resell information:

a. **Secondary Provider Capacity Posting (Input)** (secondatcpost) shall be used by the Secondary Provider to post on to the OASIS Node the transmission capacity for resale.
   - PRIMARY_PROVIDER
   - SELLER_NAME
   - PATH_NAME
   - POINT_OF_RECEIPT
   - POINT_OF_DELIVERY
   - INTERFACE_TYPE
   - ANCILLARY_SERVICES_REQUIREMENTS
   - REQUEST_REF
   - BEGDATETZ
   - ENDDATETZ
   - CAPACITY
   - CAPACITY_TYPE
   - TERMS_AND_CONDITIONS
   - SELLER_NAME
   - SELLER_COMPANY
   - SELLER_PHONE

- SELLER_FAX
- SELLER_EMAIL
- PREV_ASSIGN_REF
- REASSIGNED_CAPACITY (Capacity from each previous assignment being offered for sale)
- REASSIGNED_BEGDATETZ
- REASSIGNED_ENDDATETZ
- COMMENTS
- HOUR
- PRICE
- PRICE_UNITS

b. **Secondary Provider (Reseller) Capacity Remove (Input)** (secondatcremove) shall be used by the Secondary Provider to remove a posting of transmission capacity.
- PRIMARY_PROVIDER
- SELLER_NAME
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- INTERFACE_TYPE
- ANCILLARY_SERVICES_REQUIREMENTS
- REQUEST_REF
- BEGDATETZ
- ENDDATETZ
- CAPACITY(Total capacity being removed)
- CAPACITY_TYPE
- TERMS_AND_CONDITIONS
- SELLER_NAME
- SELLER_COMPANY
- SELLER_PHONE
- SELLER_FAX
- SELLER_EMAIL
- PREV_ASSIGN_REF
- REASSIGNED_CAPACITY (Capacity being removed from each previous reassignment)
- REASSIGNED_BEGDATETZ
- REASSIGNED_ENDDATETZ
- COMMENTS

4.3.4 <u>Services Information Templates</u>

a. **Ancillary Services Available for Purchase** (servavail) is used to provide information regarding the different services that are available for sale by a Service Provider.
- ANCILLARY_SERVICE_ PROVIDER

- ANCILLARY_SERVICE_CATEGORY
- ANCILLARY_SERVICE_TYPE
- SELLER_NAME
- SELLER_COMPANY
- SELLER_PHONE
- SELLER_FAX
- SELLER_EMAIL
- PRICE
- PRICE_UNITS
- DTTZTS_POSTED
- DTTZTS_EXPIRES
- COMMENTS
- SERVICE_DESCRIPTION

b. **Services Transmission** (servtrans) is used to provide detailed information regarding the transmission services that are available for sale by a Primary Provider in the Templates in Section 4.3.2. This Template is used to summarize tariff information for the convenience of the Customer. Fields which are not used may have "Not Applicable" assigned to them. (Optional)

- TARIFF_REFERENCE
- PRIMARY_ PROVIDER
- SERVICE_CATEGORY
- SERVICE_TYPE
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- RATE_INFORMATION
- UNITS
- COMMENTS
- RECALLABLE_REASONS
- RECALLABLE_MINIMUM_NOTICE
- RECALLABLE_QUEUE_ORDER
- RECALLABLE_RESUMPTION
- CURTAILMENT_REASONS
- CURTAILMENT_MINIMUM_NOTICE
- CURTAILMENT_QUEUE_ORDER
- CURTAILMENT_RESUMPTION
- SERVICE_TIMING_MINIMUM_DURATION
- SERVICE_TIMING_MAXIMUM_DURATION
- CUSTOMER_PAYMENT
- ASSIGNABILITY
- INCREASE_OBLIGATION
- LOSS_OBLIGATION
- CUSTOMER_REQUIREMENTS

- PROVIDER_OPTIONS

4.3.5 "Service Request" Transaction Templates

The Primary Provider shall assign a unique assigned reference identifier for each customer request to purchase capacity or services. This identifier will be used to track the request through various stages.

a. **Customer Capacity Purchase Request (Input)** (atcrequest) is used by the Customer to request the purchase of transmission services.
   - CUSTOMER
   - PATH_NAME
   - POINT_OF_RECEIPT
   - POINT_OF_DELIVERY
   - SELLER_NAME (Secondary Provider)
   - SOURCE
   - SINK
   - CAPACITY
   - CAPACITY_TYPE
   - BEGDATETZ
   - ENDDATETZ
   - REQUEST_REF
   - PRICE
   - PRICE_UNITS
   - DISCOUNT
   - DEAL_REFERENCE
   - ANCILLARY_SERVICES_REQUIREMENTS
   - INTERFACE_TYPE
   - COMMENTS

b. **TSIP Posting of "Acknowledge Receipt" of Request** (atcacknowledge)is used to acknowledge that the Customer's request was received by the OASIS Node. It does not imply that the Provider has received the request.
   - CUSTOMER
   - PATH_NAME
   - POINT_OF_RECEIPT
   - POINT_OF_DELIVERY
   - SELLER_NAME
   - SOURCE
   - SINK
   - CAPACITY
   - CAPACITY_TYPE
   - BEGDATETZ
   - ENDDATETZ

- ASSIGNMENT_REF
- REQUEST_REF
- PRICE
- PRICE_UNITS
- DISCOUNT
- DEAL_REFERENCE
- ANCILLARY_SERVICES_REQUIREMENTS
- INTERFACE_TYPE
- COMMENTS

c. **Provider Capacity Purchase Status Response to Customer Request** (atcstatus) is posted upon the request of a Customer, to indicate the status and queue of the request. It is almost identical to the Customer Purchase Request, but includes a Status field, a Queue field, and an Assignment Reference identifier assigned by the Primary Provider, which will be used to track all transactions for specific Capacity.

When a Customer calls up the Template, all posted requests for that Customer are retrieved. Only the authorized Customer is permitted to view this information.

When a Secondary Provider calls up the Template, all posted requests for that Secondary Provider are retrieved. Only the authorized Secondary Provider is permitted to view this information.

The following information is included:

- PRIMARY_PROVIDER
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- SELLER_NAME
- SOURCE
- SINK
- CAPACITY (of total transaction)
- CAPACITY_TYPE
- BEGDATETZ
- ENDDATETZ
- REQUEST_REF
- CUSTOMER
- PRICE
- PRICE_UNITS
- DISCOUNT
- DEAL_REFERENCE
- SERVICE_DESCRIPTION
- ASSIGNMENT_REF

- STATUS = **None, Pending, Received, Accepted by Customer, Accepted by Seller, Confirmed for Scheduling, Withdrawn, or Rejected**
- INTERFACE_TYPE
- DTTZTS_QUEUED
- COMMENTS
- PREV_ASSIGN_REF
- REASSIGNED_CAPACITY (Capacity from each previous transaction)
- REASSIGNED_STATUS= **Posted, Received, Accepted by Seller, Accepted by Customer, Withdrawn, or Rejected**
- REASSIGNED_BEGDATETZ
- REASSIGNED_ENDDATETZ
- COMMENTS

d. **Customer's Purchase Acknowledge Acceptance (Input)** (atcaccept) is used by the Customer to acknowledge his agreement or rejection of a purchase after the Provider has indicated that the purchase request is accepted. It is identical to the Provider Response.

- CUSTOMER
- PRIMARY_ PROVIDER
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- SELLER_NAME
- SOURCE
- SINK
- CAPACITY
- CAPACITY_TYPE
- BEGDATETZ
- ENDDATETZ
- REQUEST_REF
- PRICE
- PRICE_UNITS
- DISCOUNT
- DEAL_REFERENCE
- SERVICE_DESCRIPTION
- ASSIGNMENT_REF
- STATUS =**Accepted or Rejected**
- INTERFACE_TYPE
- DTTZTS_QUEUED
- COMMENTS

e. **Seller Form to Acknowledge Capacity Purchase Status (Input)** (sellerack) is used by a Secondary Provider to indicate the status and queue of a request by a Customer. It is almost identical to the Customer Purchase Request, but includes a Status field, a

Queue field, and a Schedule Reference number assigned originally by the Primary Provider, which will be used to track all transactions for the specific Capacity.

The following information is included in the Form:

- CUSTOMER
- PRIMARY_PROVIDER
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- SELLER_NAME
- SOURCE
- SINK
- CAPACITY (Total capacity acknowledged)
- CAPACITY_TYPE
- BEGDATETZ
- ENDDATETZ
- REQUEST_REF
- PRICE
- PRICE_UNITS
- DISCOUNT
- DEAL_REFERENCE
- SERVICE_DESCRIPTION
- ASSIGNMENT_REF
- INTERFACE_TYPE
- DTTZTS_QUEUED
- PREV_ASSIGN_REF
- REASSIGNED_CAPACITY(Previous capacity to be reassigned)
- REASSIGNED_STATUS= **Received, Accepted by Seller, Withdrawn, or Rejected**
- REASSIGNED_BEGDATETZ
- REASSIGNED_ENDDATETZ
- COMMENTS

f. **Seller Form to Reassign Service Rights to Another Customer (Input)** (sellerrassign) is used by the Secondary Provider to ask the Transmission Services Information Provider to reassign some or all of the Seller's rights to Services to another Customer, following a confirmation of a sale of these services from that Customer.

- CUSTOMER
- PRIMARY_PROVIDER
- PATH_NAME
- POINT_OF_RECEIPT
- POINT_OF_DELIVERY
- SELLER_NAME

- SOURCE
- SINK
- CAPACITY (Total capacity being sold)
- CAPACITY_TYPE
- BEGDATETZ
- ENDDATETZ
- REQUEST_REF
- PRICE
- PRICE_UNITS
- DISCOUNT
- DEAL_REFERENCE
- SERVICE_DESCRIPTION
- ASSIGNMENT_REF
- INTERFACE_TYPE
- DTTZTS_QUEUED
- PREV_ASSIGN_REF
- REASSIGNED_CAPACITY (Capacity being sold from each previous assignment)
- REASSIGNED_BEGDATETZ
- REASSIGNED_ENDDATETZ
- REASSIGNED_STATUS = **Accepted or Rejected**
- COMMENTS

4.3.6 Informal Information Templates

a. **Provider/Customer Want-Ad Posting Request (Input)** (wantadpost) is used by Providers and Customers who wish to advertise.
   - PROVIDER or CUSTOMER
   - COMPANY
   - PHONE
   - FAX
   - EMAIL
   - DTTZTS_POSTED
   - DTTZTS_EXPIRES
   - KEYWORD
   - SUBJECT
   - WANT-AD

b. **TSIP Posting of Want-Ad Response** (wantadlisting) is the response of the TSIP to a Want-Ad posting request. The contents are identical to the request.
   - PROVIDER or CUSTOMER
   - CONTACT
   - PHONE
   - FAX
   - E-MAIL

- DTTZTS_POSTED
- DTTZTS_EXPIRES
- KEYWORD
- SUBJECT
- WANT-AD

4.4 FILE REQUEST AND FILE DOWNLOAD EXAMPLES

4.4.1 File Example for Summary Path Hourly ATC

Example of the request and response for path "W/AAAA/PATH-ABC//" for today.

- **Request**

http://(OASIS Node name)/OASIS/wxyz/cgi/sumpathouratc?&ver=1.0&fmt=data&
dtz=19960412043010ED& pprovider=wxyz& path=W/AAA/PATHABC//& relday=0& shr=0&
her=14& capacity_type1=firm& capacity_type2=non-firm

- **Response Data**

```
REQUEST-STATUS=200          ↵        (Successful)
VERSION=1.0↵
DATETIMETZ="19960410113526PD" ↵
PRIMARY_PROVIDER=wxyz↵
DATA_ROWS=30↵
COLUMN_HEADERS="PROVIDER","PATH_NAME","POR","POD","IT","CT","CAP","DTMM
TZ","COMMENTS" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100100PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100100PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100200PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100200PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100300PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100300PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100400PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100400PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100500PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100500PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100600PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100600PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100700PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100700PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100800PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100800PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604100900PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604100900PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604101000PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604101000PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604101100PD","N/A" ↵
```

"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604101100PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604101200PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604101200PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604101300PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604101300PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604101400PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604101400PD","N/A"↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","FIRM",300,"199604101500PD","N/A" ↵
"AAA","W/AAA/PATHABC//","N/A","N/A","E","NON-FIRM",500,"199604101500PD","N/A"↵

4.4.2 File Example for Hourly Schedule Data

This example shows a request for the hourly schedule data. This demonstrates how to specify query variables from a file.

- **Request**

URL Request (HTTP method=GET)

http://(OASIS Node name)/OASIS/wxyz/cgi/scheduledatc& ver=1.0& fmt=data& dtz=19960412043010ED& pprovider=wxyz &por=BBB &pod=CCC &relday=1 &hour-start=08 &hour-end=17

URL Request (HTTP method=POST)

$ fetch_http http://(OASIS Node name)/OASIS/wxyz/cgi/OASISdata -f *c:/OASIS/wxyz/upload/inputfile.txt*

Where *inputfile.txt* contains the following:

Template=scheduledatc& ver=1.0 & fmt=data& dtz=19960412044010CD& pprovider=wxyz& por=BBB& pod=CCC &relday=1 &hour-start=08 &hour-end=17

- **Response Data**

REQUEST-STATUS=200↵
VERSION=1.0↵
DATETIMETZ=19960410114702PD↵
PROVIDER=*wxyz*↵
DATA_ROWS=50↵
COLUMN_HEADERS="PATH_NAME","POR","POD","SOURCE","SINK","REF","IT","CUSTOMER","DEAL","CT","CAP","DTMMTZ",...↵
"AAA","AAABBB","BBB","CCC","source","sink","794245","E","BPA","deal","NON-FIRM",50,"199604100800PD","","" ↵
...↵
...↵

"AAA","AAABBB","BBB","CCC","source","sink","795000","E","BPA","deal","FIRM",39,"199604101700PD","","" ↵

4.4.3 Customer Capacity Purchase Request

This example shows how a customer might make a request to purchase capacity from a provider. The information to be sent to the provider is specified using Query Variables in a file. The example uses the FETCH_HTTP program to send a file to the OASIS node.

- **Request File purchase.txt**

template= atcrequest& fmt=data& ver=1.0& dtz=19960412043010MD& pprovider=abcd &por=aaa&pod=bbb&path=aaa1bbb1&source=src1& sink=sink1& capacity=100& capacity_type=non-firm& year=1996& month=04&day-start=15& day-end=20& tz=pd& price=1.00& customer=cust1& deal_ref=1234567800& comments="Example purchase request"

FETCH_HTTP Command to send purchase request

$ fetch_http http://(OASIS Node name)/OASIS/abcd/cgi/atcrequest -f c:/OASIS/abcd/upload/*purchase.txt*

- **Response Data**

REQUEST-STATUS=200↵
VERSION=1.0↵
DATATIMEZ=19960412073500PD↵
PRIMARY_PROVIDER=abcd↵
DATA_ROWS=1↵
COLUMN_HEADERS= "BEGDATETZ", "ENDDATETZ", "ASSIGNMENT_REF", "PROVIDER", "PATH", "POR", "POD", "SELLER_NAME", "SOURCE", "SINK", "CAPACITY", "CAPACITY_TYPE", "REQUEST_REF", "DEAL_REFERENCE", "COMMENTS"↵
"19960415000100PD", "19960420002400PD", "ABC998553", "ABC", "AAA1BBB1", "AAA", "AAA", "ABC", "src1", "sink1", "100", "NON-FIRM", "", "1234567800", "Example Purchase Request" ↵

4.4.4 Capacity Purchase Status

- **Request URL**

http://(OASIS Node name)/OASIS/abc/cgi/atcstatus? ver=1.0& fmt=data& dtz=19960412043010ED& pprovider=wxyz& customer=cust1& year=1996&month=04

- **Response Data**

REQUEST-STATUS=200 ↵
VERSION=1.0↵
DATATIMEZ=19960412090215PD↵
PRIMARY_PROVIDER=*wxyz*↵
DATA_ROWS=1↵
COLUMN_HEADERS=BEGDATETZ, ENDDATETZ, ASSIGNMENT_REF, PROVIDER, PATH, POR, POD, SELLER_NAME, SOURCE, SINK, CAPACITY, CAPACITY_TYPE, REQUEST_REF,

DEAL_REFERENCE, COMMENTS, STATUS, ASSIGNMENT_REF, DTTZTS_QUEUED, NO_PREF_ASSIGN_REF↵
"19960415000100PD", "19960420002400PD", "ABC998553", "ABC", "AAA1BBB1", "AAA", "AAA", "ABC", "src1", "sink1", "100", "NON-FIRM", "", "1234567800", "Example Purchase Request", "Accepted by Seller", "ABC998532", "19960412080000PD", "0" ↵

4.4.5 Customer's Purchase Acknowledge Acceptance (Input)

- ***Customer Input File: accept.txt***

TEMPLATE=atcaccept &VERSION=1.0& FORMAT=data& &dtz=19960412043010ED& provider=wxyz &STATUS="Accepted" & BEGDATETZ=19960415000100PD &ENDDATETZ=19960420002400PD &ASSIGNMENT_REF=ABC998553 &PROVIDER=wxyz &PATH=AAA1BBB1 &POR=AAA &POD=AAA &SELLER_NAME=ABC &SOURCE=src1 &SINK=sink1 &CAPACITY=100 &CAPACITY_TYPE=NON-FIRM &REQUEST_REF= &DEAL_REFERENCE=1234567800 &COMMENTS="Example Purchase Request" &ASSIGNMENT_REF="ABC998532" &DTTZTS_QUEUED=19960412080000PD &NO_PREF_ASSIGN_REF=0

FETCH_HTTP command

$ fetch_http http://(OASIS node name)/OASIS/(provider)/cgi/atcaccept -f c:\OASIS\wxyz\upload*accept.txt*

5. PERFORMANCE REQUIREMENTS

A critical aspect of any system is its performance. Performance encompasses many issues, such as security, sizing, response to user requests, availability, backup, and other parameters that are critical for the system to function as desired. The following sections cover the performance requirements for the OASIS.

5.1 SECURITY

Breaches of security include many inadvertent or possibly even planned actions. Therefore, several requirements shall be implemented by the TSIPs to avoid these problems:

a. **Provider Update of TS Information:** Only Providers, including Secondary Providers, shall be permitted to update their own TS Information.

b. **User Input Only ASCII Text:** TSIPs shall be permitted to require that inputs from Customers shall be filtered to permit only strict ASCII text (strip bit 8 from each byte).

c. **Provider Updating Over Public Facilities:** If public facilities are involved in the connection between a Provider and the OASIS Node, the Provider shall be able to update his TS Information only through the use of ASCII or through encrypted files.

d. **User Registration and Login:** All Users shall be required to register and login to a Provider's Account before accessing that Provider's TS Information.

e. **User Passwords:** All Users shall enter their personal password when they wish access to TS Information beyond the lowest Access Privilege.

f. **Service Request Transactions:** Whenever Service Request transactions are implemented entirely over the OASIS, Customer Service Request requests shall require both an individual Customer password for the request, and an individual Provider password for the notification of acceptance.

g. **Data Encryption:** Sophisticated data encryption techniques and the "secure id" mechanisms being used on the public Internet shall be used to transfer sensitive data across the Internet and directly between OASIS Nodes.

h. **Viruses:** TSIPs shall be responsible for protecting the OASIS Nodes from viruses.

i. **Performance Log:** TSIPs shall keep a log on User usage of OASIS resources.

j. **Disconnection:** TSIPs shall be allowed to disconnect any User who is degrading the performance of the OASIS Node through the excessive use of resources, beyond what is permitted in their Service Level Agreement.

k. **Premature Access:** The TSIP log shall also be used to ensure that Users who are affiliated with the Provider's company (or any other User) do not have access to TS information before it is publicly available.

l. **Firewalls:** TSIPs shall employ security measures such as firewalls to minimize the possibility that unauthorized users shall access or modify TS Information or reach into Provider or User systems. Interfaces through Public Data Networks or the Internet shall be permitted as long as these security requirements are met.

m. Certificates and Public Key Standards (optional) Use of alternative forms of login and authentication using certificates and public key standards is acceptable.

5.2 ACCESS PRIVILEGES

Users shall be assigned different Access Privileges based on external agreements between the User and the Provider. These Access Privileges are associated with individual Users rather than just a company, to ensure that only authorized Users within a company have the appropriate access.

The following Access Privileges shall be available as a minimum:

a. **Access Privilege Read-Only:** The User may only read publicly available TS information.

b. **Access Privilege for Transactions:** The Customer is authorized to transact Service Request requests.

c. **Access Privilege Read/Write:** A Secondary Provider shall have write access to his own Provider Account on a OASIS Node.

5.3 OASIS RESPONSE TIME REQUIREMENTS

TSIPs can only be responsible for the response capabilities of two portions of the Internet-based OASIS network:

- The response capabilities of the OASIS Node server to process interactions with Customers
- The bandwidth of the connection(s) between the OASIS Node server and the Internet.

Therefore, the OASIS response time requirements are as follows:

a. **OASIS Node Server Response Time:** The OASIS Node server shall be capable of supporting its connection(s) to Users with an average aggregate data rate of at least "A" bits per second. "A" is defined as follows:

$$A = N * R \text{ bits/sec}$$

where:

$$N = 5\% \text{ of registered Customers.}$$

and

$$R = 28{,}800 \text{ bits/sec per Customer.}$$

b. **OASIS Node Network Connection Bandwidth:** The bandwidth "B" of the OASIS Node connection(s) to the Internet shall be at least:

$$B = 2 * A \text{ bits/sec}$$

c. **Time to Meet Response Requirements:** The minimum time responses shall be met **within 1 month of User registration** for any single new User. If more than 10 new Users register in one month, 2 months lead time shall be permitted to expand/upgrade the OASIS Node to meet the response requirements.

5.4 OASIS PROVIDER ACCOUNT AVAILABILITY

The following are the OASIS Provider Account availability requirements:

a. **OASIS Provider Account Availability:**The availability of each OASIS Provider

a. **OASIS Provider Account Availability:** The availability of each OASIS Provider account on a OASIS Node shall be at least **98.0%** (downtime of about 7 days per year).

Availability is defined as:

$$\% \text{ Availability} = \frac{(1 - \text{Cumulative Provider Account Downtime})}{\text{Total Time}} * 100$$

A Provider account shall be considered to be down, and downtime shall be accumulated, upon occurrence of any of the following:

1. One or more Users can not link and log on to the Provider account. The downtime accumulated shall be calculated as:
   - Σ **for affected Users of 1/n * (Login Time)**, which is the time used by each affected User to try to link and log on to the Provider account, and where "n" is the total number of Users actively registered for that Provider account.

2. One or more Users can not access TS Information once they have logged on to a Provider account. The downtime accumulated shall be calculated as:
   - Σ **for affected Users of 1/n * (Access Time)**, which is the time used by each affected User to try to access data, and where "n" is the total number of Users actively registered for that Provider.

3. A **five (5) minute** penalty shall be added to the cumulative downtime for every time a User loses their connection to a Provider's account due to a OASIS Node momentary failure or problem.

5.5 BACKUP AND RECOVERY

The following backup and recovery requirements shall be met:

a. **Normal Backup of TS Information:** Backup of TS Information and equipment shall be provided within the OASIS Nodes so that no data or transaction logs are lost or become inaccessible by Users due to any single point of failure. Backed up data shall be no older than **30 seconds.** Single points of failure include the loss of one:

- Disk drive or other storage device
- Processor
- Inter-processor communications (e.g. LAN)
- Inter-OASIS communications
- Software application
- Database
- Communication ports for access by Users
- Any other single item which affects the access of TS Information by Users

b. **Spurious Failure Recovery Time:** After a spurious failure situation, all affected Users shall regain access to all TS Information **within 30 minutes**.

c. **Long-Term Backup:** Permanent loss of critical data due to a catastrophic failure shall be minimized through off-line storage on a **daily basis** and through off-site data storage on a **periodic basis**.

d. **Catastrophic Failure Recovery:** Recovery from a catastrophic failure or loss of a OASIS Node may be provided through the use of alternate OASIS Nodes which meet the same availability and response time requirements. TSIPs may set up prior agreements with other TSIPs as to which Nodes will act as backups to which other Nodes, and what procedure will be used to undertake the recovery. Recovery from a catastrophic failure shall be designed to be achieved **within 24 hours**.

5.6 TIME SYNCHRONIZATION

The following are the time requirements:

a. **Time Synchronization:** Time shall be synchronized on OASIS Nodes such that all time stamps will be accurate to within ± 0.5 second of official time. This synchronization may be handled over the network using NTP, or may be synchronized locally using time standard signals (e.g. WWVB, GPS equipment).

b. **Network Time Protocol (NTP):** OASIS Nodes shall support the Internet tool for time synchronization, Network Time Protocol (NTP), which is described in RFC-1305, version 3, so that Customers shall be able to request the display and the downloading of current time on a OASIS Node for purposes of user applications which might be sensitive to OASIS time.

5.7 TS INFORMATION TIMING REQUIREMENTS

TO BE COMPLETED BY THE INDUSTRY

5.8 TS INFORMATION ACCURACY

The following requirements relate to the accuracy of the TS information:

a. **TS Information Reasonability:** TS information posted and updated by the Provider shall be validated for reasonability and consistency through the use of limit checks and other validation methods.

b. **TS Information Accuracy:** Although precise measures of accuracy are difficult to establish, Providers shall use their best efforts to provide accurate information.

5.9 PERFORMANCE AUDITING

The following are the performance auditing requirements:

a. **User Help Desk Support**: TSIPs shall provide a "Help Desk" that is available at least during normal business hours (local time zone) and normal work days.

b. **Time-Stamped OASIS Performance Log:** All posting of TS information, all updating of TS information, all User logins and disconnects, all User download requests, all Service Request requests, and all other transactions shall be time stamped and stored in a OASIS Performance Log. This OASIS Performance Log shall be the official log for auditing performance, as well as acting as the official record of interactions.

c. **Monitoring Performance Parameters:**TSIPs shall use their best efforts to monitor performance parameters. Any Customer shall be able to read or download these performance statistics.

5.10 MIGRATION REQUIREMENTS

The following are the migration requirements:

a. **Support for Legacy Capabilities:** Any time mandated upgrades or modifications to OASIS capabilities and tools are made to the OASIS, TSIPs shall continue to support the existing capabilities and tools for at least 3 months. This overlap will permit Customers the time to upgrade their own systems to reflect these changes.

[NOTE: This appendix will not appear in the Code of Federal Regulations.]

Appendix A

Data Element Dictionary

April 24, 1996

Version 1.0

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
ANCILLARY_SERVICES_ CATEGORY (alias ANC_SERV_CAT)	Category of ancillary services (to be defined)	1{ALPHANUMERIC}20	Text	Free-form text	A reference to ancillary service categoried defined by the Provider
ANCILLARY_SERVICES_ PROVIDER (alias ANC_SERV_PROVIDER)	Provider of ancillary services	1{ALPHANUMERIC}25	Name	Unique value	Name of a provider of ancillary services
ANCILLARY_SERVICES_ REQUIREMENTS (alias ANC_SERV_REQ)	Requirements for Ancillary Services	1{ALPHANUMERIC} 50	Text	Free-form text	Requirements for Ancillary Services
ANCILLARY_SERVICES_ TYPE (alias (ANC_SERV_TYPE)	Type of ancillary services (to be defined)	1{ALPHANUMERIC}14	Text	Free-form text	A reference to the ancillary service types defined by the Provider. This provides a sub-category for ANCILLARY_SERVICE_CATEGORY
ASSIGNABILITY	Assignability	2{ALPHA}3	Boolean	YES or NO	Identifies whether service is assignable or not.
ASSIGNMENT_REF (ALIAS ASSIGN_REF)	Reference for Assignment of ATC Rights	1{ALPHANUMERIC}12	Text	Unique value	A unique reference number assigned by a Transmission Information Provider to provide a unique record for each transmission service request.
BEGDATETZ (alias BEGDTZ)	Beginning Date and Time	16 alphanumeric characters: yyyy+mo+dd+hh+mm+ss+ tz	Time	Valid date and time	Beginning Date, time, and time zone. Military time is used. Example: 19960212145530PS
CAPACITY (alias CAP,ATC)	Available Transmission Capacity or Available Transfer Capability	1{NUMERIC}12	MW	Positive number	Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. In this context, 'area' may be an individual electric system, power pool, control area, subregion, or NERC region, or portion thereof.
CAPACITY_TYPE (alias CAP_TYPE,ATC_TYPE)	Type of Capacity	1{ALPHANUMERIC}14	Text	The value is selected from the _TYPE element described by the Provider in his Services_ Transmission	The type of capacity being referenced. *Examples include Firm, Non-Firm; Firm-On-Peak, Firm-Off-Peak, Non-Firm-On-Peak, Non-Firm-Off-Peak;*

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
COLUMN_HEADERS (alias HEADERS	Column headers for data	1{ALHANUMERIC}Unlimited	Text	Headers surrounded with " and seperated by commas	Example: "PATH_NAME","POR","POD","SOURCE","SINK"
COMMENTS	Comments	1{ALPHANUMERIC} 50	Text	Free-form text	Informative text.
COMPANY	Company of a Primary Provider, Secondary Provider, or Customer	1{ALPHANUMERIC}25	Name	Valid name of a Company	The name of a Company who has services for resell.
CONTACT	Contact name	1{ALPHANUMERIC}25	Name	Valid name of a person	The name of an individual contact.
CURTAILMENT_ RESUMPTION (alias CURT_RESUMP)	Curtailment Resumption	1{NUMERIC}12	Priority number	Positive number	Priority in which service is resumed.
CURTAILMENT_MINIMUM_ NOTICE (alias CURT_MIN_NOTICE)	Curtailment Minimum Notice	1{ALPHANUMERIC}16	Time in Hours	Positive number	Minimum time to provide notice of curtailment of service.
CURTAILMENT_PRIORITY (alias CP)	Curtailment Priority	1{NUMERIC}3	Priority number	Positive number	The order in which the schedules will be curtailed.
CURTAILMENT_QUEUE_ORDER (alias CURT_QUE_ORDER)	Curtailment Queue Order	1{NUMERIC}3	Queue number	Positive number	Priority in which curtailment of service occurs.
CURTAILMENT_REASON (alias CURT_REASON)	Curtailment Reasons	1{ALPHANUMERIC}25	Text	Free-form text	Reason for curtailment of service.
CUSTOMER	Name of Requester and Customer Identifier (authorization password or identifier code, which at least is non-displayable and should be encrypted)	1{ALPHANUMERIC}25	Name	Unique value	Any eligible company (or its designated agent) that is authorized to view OASIS information, to execute a service agreement, and/or to receive transmission service.
CUSTOMER_CODE (alias CUST_CODE)	Transmission Customer Code	1{NUMERIC}12	DUNS number	Unique number	Unique DUNS number for each Customer (if available)
CUSTOMER_PAYMENT (alias CUST_PAYMENT)	Customer Payment	1{ALPHANUMERIC}20	Text	Free-form text	Customer payment.
CUSTOMER_REQUIREMENT (alias CUST_REQUIREMENTS)	Customer Requirements	1{ALPHANUMERIC}20	Text	Free-form text	Customer requirements.
DATA_RECORDS	Data included in a file	1{APLPHANUMERIC} unlimited	Text or numbers	Free-form text or numbers	Data included in a file

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
DATETIMETZ (alias DTZ)	Date and Time Stamp	16 alphanumeric characters: yyyy+mo+dd+hh+mm+ss+tz	Time	Valid date and time	Date and Time Stamp of the information being presented to the Customer
DAY	Day	Query Variable	Numeric	The day is represented as an integer from 1 to 31. For some months, the maximum value may be less.	This specifies the day of the month from which the data is requested. DAY refers to a single day, while DAY-START and DAY-END refer to a range of days.
DAY-END, (alias EDAY)	Last day to show data	Query Variable	Numeric	The day is represented as an integer from 1 to 31. For some months, the maximum value may be less.	This specifies the day of the month from which the data is requested. DAY refers to a single day, while DAY-START and DAY-END refer to a range of days.
DAY-START, (alias SDAY)	First day to show data	Query Variable	Numeric	The day is represented as an integer from 1 to 31. For some months, the maximum value may be less.	This specifies the day of the month from which the data is requested. DAY refers to a single day, while DAY-START and DAY-END refer to a range of days.
dd	Days in date and time fields	2{NUMERIC}2	Time	Range of 0 to 31, validated against month	A numeric value represent the day in the month

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
DEAL_REFERENCE (alias DEALREF)	Deal Reference	1{ALPHANUMERIC}12	Text	Unique value	The unique reference assigned by a Customer to two or more SERVICE_PURCHASES to identify each of them as related to others in the same power service deal. These requests may be related to each other in time sequence through a single Provider, or as a series of wheels through multiple Providers, or a combination of both time and wheels. The Customer uses the DEAL_REFERENCE to uniquely identify a combination of requests relating to a particular deal.
DISCOUNT	Discount	0{ALPHANUMERIC}20	Text	Free-form text	A description of any discount that applies.
DISCOUNT_PERCENT	Discount Percentage	0{NUMERIC}6	Percentage	Between 0 and 100	The percentage of any discount that applies.
DTMMTZ	Date and Time to minutes with time zone	14 alphanumeric characters: yyyy+mo+dd+hh+mm+tz	Time	Valid date and time	Date and time to the minute resolution and time zone. This specifies the time when the Capacity is available.
DTTZTS_EXPIRES	Date and time of expiration	14 alphanumeric characters: yyyy+mo+dd+hh+mm+tz	Time	Valid date and time	Represents when a Want Ad message expires (i.e., is removed from data storage).Date, time, and time zone. Military time is used. Example: 19960212145530PS
DTTZTS_POSTED	Date and time posted, oriented to computers	14 alphanumeric characters: yyyy+mo+dd+hh+mm+tz	Time	Valid date and time	Represents when a Want Ad message was posted. Date, time, and time zone oriented to computer interpretation. Military time is used. Example: 19960212145530PS
DTTZTS_QUEUED	Date and time entered into queue	16 alphanumeric characters: yyyy+mo+dd+hh+mm+ss+tz	Time	Valid date and time	Represents when a Customer Request or a Want Ad message was queued for processing. Date, time, and time zone oriented to computer interpretation. Military time is used. Example: 19960212145530PS
E-MAIL (aliad EMAIL)	E-mail address	5{ALPHANUMERIC}60	E-mail address	Valid network reference	E-MAIL address
ENDDATETZ (alias ENDDTZ)	Ending Date and Time	16 alphanumeric characters: yyyy+mo+dd+hh+mm+ss+tz	Time	Valid date and time	Ending Date, time, and time zone. Military time is used. Example: 19960212145530PS

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
FAX	Fax number	10{NUMERIC}10	Telephone number	Area code and telephone number	A telephone number for a fax machine.
hh	Hour in date and time fields	2{NUMERIC}2	Time	Range of 0 to 25	A numeric value represent the hour of the day with a range of 0 to 25. The value of 25 is necessary for observance of daylight savings time.
HOUR	Hour	Query Variable	Numeric	An integer value between 1 and 25 representing "hour-ending" time. Hour 1 refers to the time between 00:01 to 01:00. Hour 25 refers to the extra hour added when daylight savings time changes in the fall. Default is all hours of the day.	This specifies the hour of the day or range of hours in the day for each hour data is requested. HOUR refers to a single hour, while HOUR-START and HOUR-END refer to a range of hours
HOUR-END, (alias EHR)	Hour	Query Variable	Numeric	An integer value between 1 and 25 representing "hour-ending" time.	This specifies the hour of the day or range of hours in the day for each hour data is requested. HOUR refers to a single hour, while HOUR-START and HOUR-END refer to a range of hours
HOUR-START, (alias SHR)	Hour	Query Variable	Numeric	An integer value between 1 and 25 representing "hour-ending" time.	This specifies the hour of the day or range of hours in the day for each hour data is requested. HOUR refers to a single hour, while HOUR-START and HOUR-END refer to a range of hours
INCREASE_OBLIGATION (alias INC_OBLIG)	Increase Obligation	1{ALPHANUMERIC}12	Text	Free-form text	Increase obligation.

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
INTERFACE_TYPE (alias IT)	Internal or External interface to an area	1{ALPHA}1	Text	E = external I = internal O = other	The value is either the character 'I' for Internal (Intra-control area-to-control area) or the character 'E' for External (Inter-control area-to-control area) or the character 'O' for Other.
KEYWORD	Keyword	0{ALPANUMERIC}16	Text	Free-form text	A descriptive word for identification. Typically such that it would be specified for search for information.
mm	Minutes in date and time fields	2{NUMERIC}2	Time	Range of 0 to 59	A numeric value represent the minutes of the hour
mo	Month in date and time fields	2{NUMERIC}2	Time	Range of 1 to 12	A numeric value represent the month of the year
MONTH, (alias MON)	Month	Query Variable	Numeric	Month is specified as a numeric value between 1 and 12.	This specifies which month of data is requested. Normally, the date is further qualified by day (except when monthly data is requested. MONTH refers to a single month. MONTH-START and MONTH-END specify a range
MONTH-END, (alias EMON)	Last month to show data	Query Variable	Numeric	Month is specified as a numeric value between 1 and 12.	This specifies which month of data is requested. Normally, the date is further qualified by day (except when monthly data is requested. MONTH refers to a single month. MONTH-START and MONTH-END specify a range
MONTH-START, (alias SMON)	First month to show data	Query Variable	Numeric	Month is specified as a numeric value between 1 and 12.	This specifies which month of data is requested. Normally, the date is further qualified by day (except when monthly data is requested. MONTH refers to a single month. MONTH-START and MONTH-END specify a range
NO_OF_ROWS	Number of rows of data in a file	1{NUMERIC}4	Number	Range of 1 to 9999	Number of rows of data in a file
NO_PREV_ASSIGN_REF (alias NO_PAREF)	Number of previous assignment references	1{NUMERIC}4	Number	Range of 1 to 9999	The number of previous sales of transmission services that have been aggregated to form a new sale of a portion of those services.
OUTPUT_FORMAT (alias FMT)	Output Format	4{ALPHANUMERIC}4	Text	Values of: HTML, DATA,	Defines the format of the response. The information returned is used for either a Graphical User Interface (GUI) or as a File processed by a computer.

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
PATH_NAME (alias PATH)	Path name	5{ALPHANUMERIC}50	Name	Unique value	The unique name assigned to a single transmission line or the set of one or more parallel transmission lines whose power transfer capabilities are strongly interrelated and must be determined in aggregate. These lines are typically described as being on a path, corridor or interconnection in some regions, or as crossing an interface or cut-plane in other regions. Multiple lines may be owned by different parties and require prorating of capability shares. The name is constructed from the following fields, with each code separated by a "/": REGION_CODE - 2 chars, unique to OASIS System OWNER_CODE - 4 chars, unique within Region PATH_CODE - 12 chars, unique for Owner OPTIONAL_CODE - 25 chars, unique for Path. If used for directionality, then the first 12 characters shall represent POR, followed by '-', followed by 12 characters which shall represent POD SPARE_CODE - 3 chars
PHONE	Phone number	10{NUMERIC}10	Telephone number	Area code and telephone number	A telephone number.
POINT_OF_DELIVERY (alias POD)	Point of Delivery	1{ALPHANUMERIC}12	Name	Unique value	Point of Delivery is the point of interconnection on the Transmission Provider's transmission system where capacity and/or energy transmitted by the Transmission Provider will be made available to the Receiving Party. This is used along with Point of Receipt to define a Path and direction of flow on that path. For internal paths, this would be a specific location in the area. For an external path, this may be an area-to-area interface.

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
POINT_OF_RECEIPT (alias POR)	Point of Receipt	1{ALPHANUMERIC}12	Name	Unique value	Point of Receipt is the point of interconnection on the Transmission Provider's transmission system where capacity and/or energy transmitted will be made available to the Transmission Provider by the Delivering Party. This is used along with Point of Delivery to define a Path and direction of flow on that path. For internal paths, this would be a specific location in the area. For an external path, this may be an area-to-area interface.
PREV_ASSIGN_REF	Reference for Previous Assignment of ATC Rights	1{ALPHANUMERIC}12	Text	Unique value	A reference to a previous reassignment of rights, uniquely assigned by a Provider.
PRICE	Price	1{NUMERIC}5 + '.' + 2{NUMERIC}2	Dollars and cents	Positive number with 2 decimals	The offering price of the Transmission Service in dollars
PRICE_UNITS	Units for PRICE	5(ALPHA)6	Name	MW-HR, MW-DAY, KW-WK, KW-MO, KW-YR	The units used for PRICE. MW-Megawatts, KW-Kilowatts, HR-Hour, WK-Week, YR-Year
PRIMARY_ PROVIDER (alias PPROVIDER)	Primary Provider	1{ALPHANUMERIC}25	Name	Unique value	Name of an Owner of transmission services
PROVIDER	Primary or Secondary Provider	1{ALPHANUMERIC}25	Name	Unique value	Name of PRIMARY_PROVIDER or SECONDARY_PROVIDER
PROVIDER_CODE	Provider DUNS number	1{NUMERIC}12	DUNS number	Valid DUNS number	Unique code for each Primary and Secondary Provider.
PROVIDER_OPTIONS	Provider Options	1{ALPHANUMERIC}50	Text	Free-form text	Represents options offered by the Provider.
RATE_INFORMATION	Rate information related to transmission services	1{ALPHANUMERIC}50	Text	Free-form text	Rate information related to transmission services
REASSIGNED_BEGDATETZ	Beginning Date and Time	16 alphanumeric characters: yyyy+mo+dd+hh+mm+ss+ tz	Time	Valid date and time	Date and time of the beginning of the transmission service that is reassigned to another customer.

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
REASSIGNED_CAPACITY (alias REASIGN_CAP)	Transmission Capacity or Transfer Capability that is being reassigned to another customer	1{NUMERIC}12	MW	Positive number, cannot exceed previous purchase	Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. In this context, 'area' may be an individual electric system, power pool, control area, subregion, or NERC region, or portion thereof.
REASSIGNED_ENDDATEZ	End Date and Time	16 alphanumeric characters: yyyy+mo+dd+hh+mm+ss+tz	Time	Valid date and time	Date and time of the end of the transmission service that is reassigned to another customer.
REASSIGNED_STATUS	Status	4{ALPHABETIC}25	Text	Valid field	Valid entries include: Posted, Received, Accepted by Seller, Accepted by Customer, Withdrawn, Rejected
RECALLABLE_MINIMUM_NOTICE (alias REC_MIN_NOTICE)	Recallable Minimum Notice	1{ALPHANUMERIC}16	Text	Free-form text	Description by the Provider regarding time to notify that a service will be recalled.
RECALLABLE_QUEUE_ORDER (alias REC_QUE_ORDER)	Recallable Queue Order	1{ALPHANUMERIC}16	Text	Free-form text	Description by the Provider of the relative position of a services request to others of a similar type.
RECALLABLE_REASON (alias REC_REASON)	Recallable Reasons	1{ALPHANUMERIC}16	Text	Free-form text	Description by the Provider regarding conditions for services being recalled.
RECALLABLE_RESUMPTION (alias REC_RESUMP)	Recallable Resumption	1{ALPHANUMERIC}16	Text	Free-form text	Description by the Provider regarding resumption of services.
REGION	Name of Region	1{ALPHANUMERIC}12	Text	Unique within OASIS System	Unique name for each area within the OASIS
REGION_CODE	Code for Region	1{ALPHANUMERIC}2	Code	Unique within OASIS System	Unique Defined for NERC regions, with the following defined: E - ECAR I - MAIN S - SERC T - ERCOT A - MAPP P - SPP M - MAAC N - NPCC W - WSCC

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
RELATIVE_DAY, (alias RDAY)	Day relative to today	Query Variable	Numeric	Number greater than or equal to zero	This represents a value for DAY which is relative to TODAY. TODAY is represented as relative day 0. Days in the future are represented as positive values and days is the past are represented as negative values. TOMORROW is always relative day 1, while YESTERDAY is always relative day -1. This variable is used when only a single day needs to be specified. For a range of days, use the REATIVE_DAY_START and RELATIVE_DAY_END. If RELATIVE_DAY is specified, then DAY, DAY_START, and DAY_END, ELATIVE_DAY_START and RELATIVE_DAY_END must not be specified.
RELATIVE_DAY_END, (alias ERDAY)	Day relative to today for end	Query Variable	Numeric	Number greater than or equal to zero	See above
RELATIVE_DAY_START, (alias SRDAY)	Day relative to today for start	Query Variable	Numeric	Number greater than or equal to zero	See above
REQUEST_REF	Customer Request Identifier	1{ALPHANUMERIC}12	Text	Unique value	A reference uniquely assigned by a Customer to a request for service from a Provider.
REQUEST_STATUS	Status of a response to a request	1{NUMERIC}3+ALPHA	Status	Error number+!Successful/Unsuccessful	Example: 200 !Successful
SELLER_COMPANY (alias SECONDARY_PROVIDER_COMPANY, S_COMPANY)	Company of a Secondary Provider	1{ALPHANUMERIC}25	Name	Valid name of a Customer	The name of a Customer who has services for resell.
SELLER_EMAIL (alias (S_EMAIL)	Secondary Provider E-mail address	5{ALPHANUMERIC}60	E-mail address	Valid network reference	E-Mail address
SELLER_FAX (alias SECONDARY_PROVIDER_FAX), S_FAX	Secondary Provider Fax	10{NUMERIC}10	Telephone number	Area code and telephone number	The telephone number for SECONDARY_PROVIDER fax machine.

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
SELLER_NAME (alias SECONDARY_PROVIDER_NAME, S_NAME)	Secondary Provider Name	1{ALPHANUMERIC}12	Name	Valid name	The name of an individual working for a Secondary Provider Company.
SELLER_PHONE (alias SECONDARY_PROVIDER_PHONE, S_PHONE)	Secondary Provider Phone	Numeric 10{NUMERIC}10	Telephone	Area code and telephone number	The telephone number for SECONDARY_PROVIDER_NAME
SERVICE_CATEGORY (alias SERVICE_CAT)	Service Category	1{ALPHANUMERIC}20	Text	Free-form text	A reference to the various service categories defined by the Provider.
SERVICE_DESCRIPTION	Description of Services	1{ALPHANUMERIC} Unlimited	Text	Free-form text	Information text.
SERVICE_TIMING_MAXIMUM_DURATION (alias SVC_MAX_DUR)	Service Timing Maximum Duration	1{NUMERIC}10	Hours	Positive number	Maximum amount of time for service.
SERVICE_TIMING_MINIMUM_DURATION (alias SVC_MIN_DUR)	Service Timing Minimum Duration	1{NUMERIC}10	Hours	Positive number	Minimum amount of time for service.
SERVICE_TYPE	Service Type	1{ALPHANUMERIC}14	Text	Free-form text	A reference to the various service types defined by the Provider. This provides for a sub-category for SERVICE_CATEGORY.
SINK	Sink	0{ALPHANUMERIC}14	Name	Valid area name	The area in which the SINK is located.
SOURCE	Source	0{ALPHANUMERIC}14	Name	Valid area name	The area in which the SOURCE is located.
ss	Seconds in date and time fields	2{NUMERIC}2	Time	Range of 0 to 59	A numeric value represent the seconds in the minute
STATUS	Status = Pending, Posted, Received, Accepted by Customer, Accepted by Seller, Confirmed for Scheduling, None, Withdrawn, or Rejected	4{ALPHABETIC}25	Text	Valid field	Valid entries include: POSTED PENDING RECEIVED ACCEPTED BY CUSTOMER ACCEPTED BY SELLER CONFIRMED WITHDRAWN REJECTED NONE

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
SUBJECT	Subject	1{ALPANUMERIC}64	Text	Free-form text	A short descriptive phrase for summarizing information text.
TARIFF_REFERENCE	Reference to tariff	1{ALPANUMERIC}20	Text	Valid text	Valid reference to a tariff
TEMPLATE	Name of the Template:	Query Variable	Variable	Name of Template	This specifies which Template from which the data is returned. The following list are the names and valid values of the Templates.
TEMPLATE01		Query Parameter	Name	sumpathhouratc	Summary Path Hourly ATC
TEMPLATE02		Query Parameter	Name	sumpatdayatc	Summary Path Daily ATC
TEMPLATE03		Query Parameter	Name	sumpathmonthatc	Summary Path Monthly ATC
TEMPLATE04		Query Parameter	Name	sumpathyearatc	Summary Path Yearly ATC (optional)
TEMPLATE05		Query Parameter	Name	houratc	Hourly Capacity Available for Purchase
TEMPLATE06		Query Parameter	Name	dayatc	Daily Capacity Available for Purchase
TEMPLATE07		Query Parameter	Name	monthatc	Monthly Capacity Available for Purchase
TEMPLATE08		Query Parameter	Name	yearatc	Yearly Capacity Available for Purchase (optional)
TEMPLATE09		Query Parameter	Name	scheduledatc	Hourly Schedule
TEMPLATE10		Query Parameter	Name	secondatcpost	Secondary Provider Capacity Posting (Input)
TEMPLATE11		Query Parameter	Name	secondatcremove	Secondary Provider (Reseller) Capacity Remove (Input)
TEMPLATE12		Query Parameter	Name	servavail	Ancillary Services Available for Purchase
TEMPLATE13		Query Parameter	Name	servtrans	Services Transmission
TEMPLATE14		Query Parameter	Name	atcrequest	Customer Capacity Purchase Request (Input)
TEMPLATE15		Query Parameter	Name	atcacknowledge	TSIP Posting of "Acknowledge Receipt" of Request
TEMPLATE16		Query Parameter	Name	atcstatus	Provider Capacity Purchase Status Response to Customer Request
TEMPLATE17		Query Parameter	Name	atcaccept	Customer's Purchase Acknowledge Acceptance (Input)
TEMPLATE18		Query Parameter	Name	sellerack	Seller Form to Acknowledge Capacity Purchase Status (Input)
TEMPLATE19		Query Parameter	Name	sellerreassign	Seller Form to Reassign Service Rights to Another Customer (Input)
TEMPLATE20		Query Parameter	Name	wantadpost	Provider/Customer Want-Ad Posting Request (Input)
TEMPLATE21		Query Parameter	Name	wantadlisting	TSIP Posting of Want-Ad Response
TERMS_AND_CONDITIONS (alias TERM_COND)	Terms and Conditions	0{ALPHANUMERIC} Unlimited	Text	Free-form text	Short descriptions of terms and conditions.

Data Dictionary Element Name	Description	Field Format : minimum characters {type of ASCII} maximum characters	Units or Type	Restricted Values	Definition of Data Element
TIME_OF_LAST_UPDATE	Date and Time	16 alphanumeric characters: yyyy+mo+dd+hh+mm+ss+ tz	Time	Valid date and time	Date and time data was last updated on OASIS Node Example: 19960212145530PS
TOTAL_TRANSMISSION_ CAPACITY (alias TTC)	Total Transmission Capacity	1{NUMERIC}12	Megawatt hours	Positive number	Total capacity of a Path
tz	Time zone in date and time fields	2{ALPHA}2	Time	Valid text	An alphanumeric value represent the time zone, which can take the following values: ES, ED, CS, CD, MS, MD, PS, or PD
UNITS	Units	1{ALPANUMERIC}12	Units	Valid units	Description of type of entity being referenced
VERSION (alias VER)	Version	1{REAL NUMBER}6	Number	Range of 1.0 to 9999.9	Specifies which version of the OASIS Requirements specification to use when interpreting the request
WANT_AD	Want-Ad message	1{ALPHANUMERIC} Unlimited	Text	Free-form text	Information text.
YEAR	Year	4{NUMERIC}4	Time	Range of 1 to 12	A numeric value represent the year
YEAR-END, (alias EYR)	Last year to show data for	Query Variable	Numeric	Valid year	YEAR-START and YEAR-END specify a range of years.
YEAR-START, (alias SYR)	First year to show data for	Query Variable	Numeric	Valid year	YEAR-START and YEAR-END specify a range of years.
yyyy	Year in date and time fields	4{NUMERIC}4	Time	Range of 1 to 12	A numeric value represent the year

[NOTE: This appendix will not appear in the Code of Federal Regulations.]

Appendix B
Request (Query) Variables

April 24, 1996
Version 1.0

Use of Query Variables

PHASE 1 OASIS Requirements, Template-specific Query Variables

Each query of the OASIS node requests data from a specific OASIS Template in the Information Model. The user specifies which OASIS Template from which to obtain data based on a "template" query variable. The query variables allowed in a request depends upon which "template" is being requested.

For each template a description of the data request is documented.
Each query variable allowed for the template is listed afterwards. At the end of each template, there may be "Discussion Issues" related to the template.

Use of Query Variables

Summary Path Hourly ATC Template

This request returns the ATC and for transmission products (e.g. firm and non-firm transmission) by each provider of a given path for each hour on a given day.

Variables

TEMPLATE=sumpathhouratc

OUTPUT_FORMAT
VERSION

PATH-NAME
POR
POD

YEAR	(or YEAR-START and YEAR-END)
MONTH	(or MONTH-START and MONTH-END)
DAY	(or DAY-START and DAY-END)
RELDAY	(or RELDAY-START and RELDAY-END)
HOUR	(or HOUR-START and HOUR-END)
TZ	

Use of Query Variables

Summary Path Daily ATC Template

Response contains on and off-peak firm and non-firm ATC and price by each provider of a given path for a given range of days.

Variables

TEMPLATE=sumpathdayatc

OUTPUT_FORMAT
VERSION

PATH-NAME
POR
POD

YEAR (or YEAR-START and YEAR-END)
MONTH (or MONTH-START and MONTH-END)
DAY (or DAY-START and DAY-END)
RELDAY (or RELDAY-START and RELDAY-END)

Use of Query Variables

Summary Path Monthly ATC

Response contains on and off-peak firm and non-firm ATC and price by each provider for a given path for a given range of months.

Variables

TEMPLATE=sumpathmonthatc

OUTPUT_FORMAT
VERSION

PATH-NAME
POR
POD

YEAR (or YEAR-START and YEAR-END)
MONTH (or MONTH-START and MONTH-END)

Use of Query Variables

Summary Path Yearly ATC Template

Response contains on and off-peak firm and non-firm ATC and price by each provider for a given path for a given range of years.

Variables

TEMPLATE=sumpathyearatc

OUTPUT_FORMAT
VERSION

PATH-1
POR-1
POD-1

YEAR (or YEAR-START and YEAR-END)

Use of Query Variables

Hourly Capacity Available for Purchase Template

Response contains firm and non-firm ATC and price for a given provider for one or more paths for each hour on a given day.

Variables

TEMPLATE=houratc

OUTPUT_FORMAT
VERSION

PROVIDER	must be specified
PATH-NAME	(PATH or PATH1 or PATH2, etc)
POR	(or POR1 or POR2, etc)
POD	(or POD1 or POD2, etc)
YEAR	(or YEAR-START and YEAR-END)
MONTH	(or MONTH-START and MONTH-END)
DAY	(or DAY-START and DAY-END)
RELDAY	(or RELDAY-START and RELDAY-END)
HOUR	(or HOUR-START and HOUR-END)
TZ	

Use of Query Variables

Daily Capacity Available for Purchase Template

Response contains on and off-peak firm and non-firm ATC and price for a given provider for one or more paths for a given range of days.

Variables

TEMPLATE=dayatc

OUTPUT_FORMAT
VERSION

PROVIDER	must be specified
PATH-NAME	(PATH or PATH1 or PATH2, etc)
POR	(or POR1 or POR2, etc)
POD	(or POD1 or POD2, etc)
YEAR	(or YEAR-START and YEAR-END)
MONTH	(or MONTH-START and MONTH-END)
DAY	(or DAY-START and DAY-END)
RELDAY	(or RELDAY-START and RELDAY-END)

Use of Query Variables

Monthly Capacity Available for Purchase Template

Response contains on and off-peak firm and non-firm ATC and price for a given provider for one or more paths for a given range of months.

Variables

TEMPLATE=monthatc

OUTPUT_FORMAT
VERSION

PROVIDER	must be specified
PATH-NAME	(PATH or PATH1 or PATH2, etc)
POR	(or POR1 or POR2, etc)
POD	(or POD1 or POD2, etc)
YEAR	(or YEAR-START and YEAR-END)
MONTH	(or MONTH-START and MONTH-END)

Use of Query Variables

Yearly Capacity Available for Purchase Template

Response contains on and off-peak firm and non-firm ATC and price for a given provider for one or more paths for a given range of months.

Variables

TEMPLATE=yearatc

OUTPUT_FORMAT
VERSION

PROVIDER	must be specified
PATH-NAME	(PATH or PATH1 or PATH2, etc)
POR	(or POR1 or POR2, etc)
POD	(or POD1 or POD2, etc)
YEAR	(or YEAR-START and YEAR-END)

Use of Query Variables

Hourly Schedule Template

Response contains firm and non-firm ATC schedule by each customer for one or more paths for each hour in a given day. No price information is given. Customer names "might" not be visible.

Variables

TEMPLATE=scheduledatc

OUTPUT_FORMAT
VERSION

PROVIDER	must be specified
PATH-NAME	(PATH or PATH1 or PATH2, etc)
POR	(or POR1 or POR2, etc)
POD	(or POD1 or POD2, etc)
YEAR	(or YEAR-START and YEAR-END)
MONTH	(or MONTH-START and MONTH-END)
DAY	(or DAY-START and DAY-END)
RELDAY	(or RELDAY-START and RELDAY-END)
HOUR	(or HOUR-START and HOUR-END)
TZ	

Use of Query Variables

Secondary Provider Capacity Posting (Input)

Input contains information to post ATC for sale by a secondary provider.

Variables

TEMPLATE=secondatcpost

VERSION

YEAR (or YEAR-START and YEAR-END)
MONTH (or MONTH-START and MONTH-END)
DAY (or DAY-START and DAY-END)
RELDAY (or RELDAY-START and RELDAY-END)
HOUR (or HOUR-START and HOUR-END)
TZ

POR
POD
PATH
PROVIDER
CAPACITY
CAPACITY_TYPE
INTERFACE_TYPE
REQUEST_REF
PRICE
UNITS
TERMS_AND_CONDITIONS
COMMENTS
SELLER_NAME
SELLER_COMPANY
SELLER_PHONE
SELLER_FAX
SELLER_EMAIL
PREV_ASSIGN_REF
REASSIGNED_CAPACITY
BEGDATETZ
ENDDATETZ
COMMENTS

Use of Query Variables

Secondary Provider (Reseller) Capacity Remove (Input)

Input contains information about a previously posted ATC for sale by a secondary provider.

Variables

TEMPLATE=secondatcremove

VERSION

YEAR (or YEAR-START and YEAR-END)
MONTH (or MONTH-START and MONTH-END)
DAY (or DAY-START and DAY-END)
RELDAY (or RELDAY-START and RELDAY-END)
HOUR (or HOUR-START and HOUR-END)
TZ

PROVIDER
POR
POD
PATH
CAPACITY
CAPACITY_TYPE
INTERFACE_TYPE
REQUEST_REF
PRICE
UNITS
TERMS_AND_CONDITIONS
COMMENTS
SELLER_NAME
SELLER_COMPANY
SELLER_PHONE
SELLER_FAX
SELLER_EMAIL

Use of Query Variables

Ancillary Services Available for Purchase

Response contains a list of ancillary services provided by a given Service Provider.

Variables

TEMPLATE=servavail

OUTPUT_FORMAT
VERSION

PROVIDER

Use of Query Variables

Services Transmission

Response contains Transmission services tariff information about each service by the given provider.

Variables

TEMPLATE=servtrans

OUTPUT_FORMAT
VERSION

PROVIDER

Use of Query Variables

Customer Capacity Purchase Request (Input)

Input contains information necessary to purchase transmission capacity of a specific type (firm or non-firm) at a specific time.

Variables

TEMPLATE=atcrequest

OUTPUT_FORMAT
VERSION

POR
POD
PATH
CAPACITY
CAPACITY_TYPE
YEAR (or YEAR-START and YEAR-END)
MONTH (or MONTH-START and MONTH-END)
DAY (or DAY-START and DAY-END)
RELDAY (or RELDAY-START and RELDAY-END)
HOUR (or HOUR-START and HOUR-END)
TZ
PRICE
CUSTOMER
DISCOUNT
DEAL_REF
ANCILLARY_SERVICES_REQUIREMENTS
INTERFACE_TYPE
COMMENTS

Use of Query Variables

TSIP Posting of "Acknowledge Receipt" of Request

Response contains the customer capacity purchase information.

Variables

TEMPLATE=atcacknowledge

OUTPUT_FORMAT
VERSION

Use of Query Variables

Provider Capacity Purchase Status Response to Customer Request

Response contains the STATUS and QUEUE INFORMATION for a given customer capacity Purchase Request.

Variables

TEMPLATE=atcstatus

OUTPUT_FORMAT
VERSION

POR
POD
PATH
CAPACITY
CAPACITY_TYPE
YEAR (or YEAR-START and YEAR-END)
MONTH (or MONTH-START and MONTH-END)
DAY (or DAY-START and DAY-END)
RELDAY (or RELDAY-START and RELDAY-END)
HOUR (or HOUR-START and HOUR-END)
TZ
PRICE
CUSTOMER
DISCOUNT
DEAL_REF
ANCILLARY_SERVICES_REQUIREMENTS
INTERFACE_TYPE
COMMENTS

Use of Query Variables

Customer's Purchase Acknowledge Acceptance (Input)

Input contains the Provider Capacity Purchase Status for a given customer Capacity Purchase Request and an indication of acceptance or rejection of the purchase.

Variables

TEMPLATE=atcaccept

OUTPUT_FORMAT
VERSION

STATUS (must be either "Accepted" or "Rejected")

POR
POD
PATH
CAPACITY
CAPACITY_TYPE
YEAR (or YEAR-START and YEAR-END)
MONTH (or MONTH-START and MONTH-END)
DAY (or DAY-START and DAY-END)
RELDAY (or RELDAY-START and RELDAY-END)
HOUR (or HOUR-START and HOUR-END)
TZ
PRICE
CUSTOMER
DISCOUNT
DEAL_REF
ANCILLARY_SERVICES_REQUIREMENTS
INTERFACE_TYPE
COMMENTS

Use of Query Variables

Seller Form to Acknowledge Capacity Purchase Status (Input)

Input contains the Seller's status, queue, and reference number of a Customer Purchase Request.

Variables

TEMPLATE=sellerack

VERSION
STATUS
DTTZTS_QUEUED
REQUEST_REF
POR
POD
PATH
PROVIDER
SELLER_NAME
CAPACITY
CAPACITY_TYPE
CUSTOMER
DISCOUNT
DEAL_REFERENCE
SERVICE_DESCRIPTION
ASSIGNMENT_REF
INTERFACE_TYPE
COMMENTS
PREV_ASSIGN_REF The following may contain multiple values
PREV_CAPACITY
PREV_STATUS
PREV_BEGDATETZ
PREV_ENDDATETZ
PREV_COMMENTS

Use of Query Variables

Seller Form to Reassign Service Rights to Another Customer (Input)

Input contains the Seller's status, queue, and reference number of a Customer Purchase Request.

Variables

TEMPLATE=sellerreassign

VERSION
POR
POD
PATH
PROVIDER
SELLER_NAME
CAPACITY
CAPACITY_TYPE
BEGDATETZ
ENDDATETZ
REQUEST_REF
CUSTOMER
DISCOUNT
DEAL_REFERENCE
SERVICE_DESCRIPTION
ASSIGNMENT_REF
INTERFACE_TYPE
DTZZTS_QUEUED
COMMENTS

PREV_ASSIGN_REF The following may contain multiple values
PREV_CAPACITY
PREV_STATUS
PREV_BEGDATETZ
PREV_ENDDATETZ
PREV_COMMENTS

Use of Query Variables

Provider/Customer Want-Ad Posting Request (Input)

Input contains the want-ad information to post on the OASIS.

Variables

TEMPLATE=wantadpost

VERSION

YEAR	Date when message expires
MONTH	
DAY	
HOUR	

CUSTOMER	(or PROVIDER)
CONTACT	must be specified
PHONE	must be specified (if FAX or E-MAIL is blank)
FAX	must be specified (if PHONE or E-MAIL is blank)
E-MAIL	must be specified (if PHONE or FAX is blank)
KEYWORD	
SUBJECT	must be specified
WANT-AD	must be specified

Use of Query Variables

TSIP Posting of Want-Ad Response

Response contains the want-ad information on the OASIS.

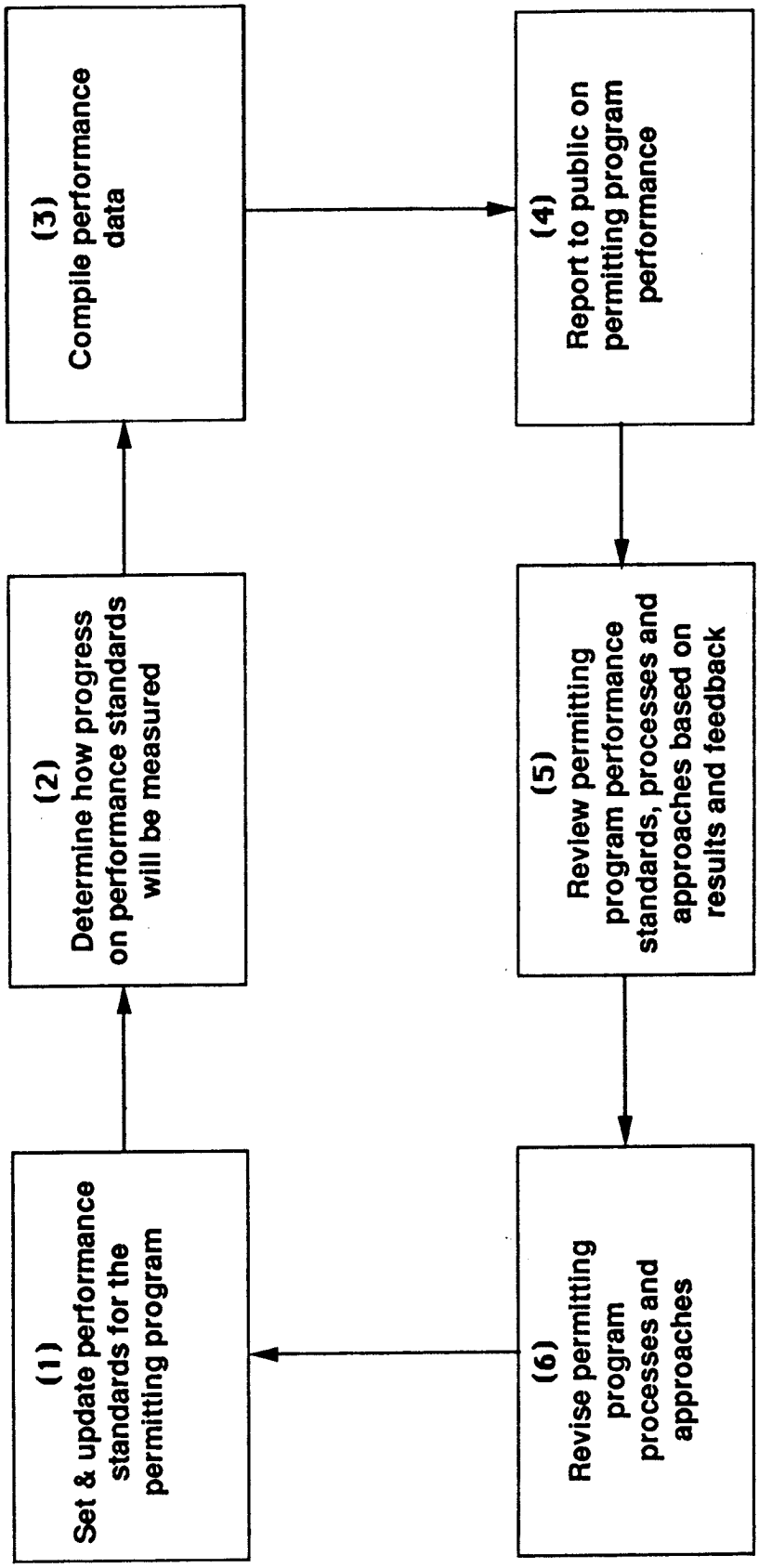
Variables

TEMPLATE=wantadlisting

OUTPUT_FORMAT
VERSION

SUBJECT [optional]
WANT-AD [optional]

Figure II:
Continuous Performance Improvement System for Permitting Programs



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BILLING CODE 6717–01–C

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM96–11–000]

Capacity Reservation Open Access Transmission Tariffs

April 24, 1996.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing a rule that specifies filing requirements to be followed by public utilities in making transmission tariff filings based on capacity reservations for all transmission users. The proposed capacity reservation open access transmission tariff, if adopted, would replace the open access transmission tariff required by the Commission in Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996). The Commission is seeking public comment on whether to require this type of tariff for all public utilities that must comply with the Commission's open access requirements, and on the specific provisions that should be contained in a capacity reservation tariff. The Commission will convene a technical conference on these issues.

DATES: Written comments must be received by the Commission by August 1, 1996. The Commission also will convene a technical conference to be held over two days in September 1996 at the Commission, 888 First Street NE., Washington, D.C. 20426. The Commission will announce the dates, time, and agenda of the technical conference at a later date.

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I. Introduction

The Federal Energy Regulatory Commission (Commission) is today adopting a final rule (Open Access Final Rule)[1] requiring each public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce to file an open access non-discriminatory transmission tariff (Final Rule tariff). The Open Access Final Rule also requires these utilities to take transmission service for their own wholesale sales and purchases of electric energy under this tariff. The Final Rule tariff specifies that service is to be provided on both a network basis and a flexible point-to-point basis; the network service is a load-based service, while the point-to-point service is based on transmission capacity reservations.

This Notice of Proposed Rulemaking (''NOPR'') requests comment on whether there are certain disadvantages inherent in offering transmission service on both a network and a point-to-point basis. If so, the Commission requests comment on whether comparability of transmission service can be better accomplished by requiring that transmission service be rendered using a single methodology. In particular, the Commission requests comment on the capacity reservation tariff (''CRT'') approach described herein. The Commission also requests comment on whether there are other methodologies that can fulfill the policy goals served by a single capacity allocation methodology as well as, or better than, the proposed CRT approach.

The proposed CRT approach would be based on the point-to-point service in the Final Rule tariff and would allow all transmission customers to have the same degree of flexibility in reserving and using transmission service. This NOPR proposes that no later than December 31, 1997, the Open Access Final Rule's network and point-to-point tariff be replaced by a CRT that provides only reservation-based transmission service for all jurisdictional service.

The Commission will hold a technical conference on this proposal prior to adopting a final rule.

II. Public Reporting Burden

The proposed rule specifies filing requirements to be followed by public utilities in making tariff filings that reflect transmission capacity reservations for all wholesale transmission customers and any unbundled retail transmission customers and would replace the open access transmission tariffs required by the Commission in the Open Access Final Rule. The information collection requirements of the proposed rule are attributable to FERC–516 ''Electric Rate Schedule Filings.'' The current total annual reporting burden for FERC–516 is 828,300 hours.

The proposed rule requires public utilities filing capacity reservation transmission tariffs to provide certain information to the Commission. The public reporting burden for the information collection requirements contained in the proposed rule is estimated to average 250 hours per response. This estimate includes time for reviewing the requirements of the Commission's regulations, searching existing data sources, gathering and maintaining the necessary data, completing and reviewing the collection of information, and filing the required information.

There are approximately 328 public utilities, including marketers and wholesale generation entities. The Commission estimates that approximately 166 of these entities own, operate, or control facilities used for the

[1] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Docket No. RM95–8–000, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996). The Open Access Final Rule is being published concurrently in the Federal Register.

transmission of electric energy in interstate commerce and will respond to the information collection. The respondents would be the same as those for the Open Access Final Rule, *i.e.*, all public utilities required to file non-discriminatory open access tariffs. Accordingly, the public reporting burden is estimated to be 41,000 hours.

Interested persons may send comments regarding the burden estimates or other aspects of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Michael Miller, (202) 208–1415], and to the Office of Information and Regulatory Affairs of the Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission (202) 395–3087).

III. Background

In the Open Access Final Rule, the Commission has adopted a pro forma tariff containing the minimum acceptable terms and conditions of transmission service for network service and for flexible point-to-point service. This type of tariff, in conjunction with other requirements imposed in the Open Access Final Rule and in the related final rule in Open Access Same-Time Information System,[2] is sufficient to remedy undue discrimination in the provision of transmission services. However, in analyzing the comments in the Open Access proceeding, it became apparent that a single service open access tariff might better accommodate competitive changes occurring in the industry while ensuring that all interstate transmission service subject to the Commission's jurisdiction is provided in a fair and non-discriminatory manner.

Network transmission service, in the Open Access Final Rule, defines rights and sets prices based on *customer load*. It allows the transmission customer to use the transmission provider's entire grid to serve designated loads from designated resources without having to pay a separate charge for each pairing of resource and load. Thus, network service enables the transmission customer to use the network flexibly to integrate its resources and loads efficiently and to dispatch economically its system, in the same way as the owner of the transmission system.

Firm flexible point-to-point service in the Open Access Final Rule, on the other hand, defines rights and sets prices based on transmission *capacity reservations*. The transmission user designates points of delivery (PODs) and points of receipt (PORs) and makes a capacity reservation for each POD and for each POR. Consistent with the comparability principle that is one of the cornerstones of the Open Access Final Rule, firm point-to-point transmission service provided to a customer must be comparable to that which the utility provides to itself. For example, the customer should be able to use any available unreserved service without an additional charge, as long as the use does not exceed its capacity reservation.

The Commission proposes to replace the network and point-to-point services in the Open Access Final Rule tariff with a CRT that would accommodate both network and point-to-point needs. The CRT would be based on the point-to-point service in the Final Rule tariff and would allow all jurisdictional transmission customers to have the same degree of flexibility in reserving and using transmission service. Under the CRT, all transmission customers would specify the amount of power to be received and delivered at multiple receipt and delivery points, and would have substantial flexibility in rearranging these receipt and delivery points. All nominations for capacity reservations would be evaluated in the same manner.[3]

IV. Reasons for Proposing a CRT

In adopting the Final Rule tariff in the Open Access Final Rule, our purpose was to remedy undue discrimination in the provision of interstate transmission service, not to reform traditional tariff design. We believe that the Final Rule tariff, in conjunction with the OASIS Final Rule, remedies undue discrimination in transmission service. The network section of the Final Rule tariff is based on the prevailing industry practice of traditional load-ratio pricing.

Many commenters responded to our initial proposed open access pro forma tariffs by asking us to adopt either more flexible or more innovative tariffs in the Open Access Final Rule. Some commenters suggested that the basic design of the Open Access NOPR pro forma tariffs may be too inflexible to accommodate industry innovations. The capacity reservation tariff proposed here is an alternative that may better suit the needs of the changing electric power industry.

The Final Rule tariff offers two types of transmission service. Network service provides enough transmission capacity to satisfy a customer's consumption of electric power. Point-to-point service sets aside as much transmission capacity as the customer reserves. Thus, network service is based on use, and point-to-point service is based on reservations.

Network customers get and pay for the capacity they use, and point-to-point customers get and pay for the capacity they reserve. The fixed costs of the transmission system are allocated among network customers on the basis of use, that is, the customers' loads. The fixed costs of the transmission system are allocated among point-to-point customers on the basis of their reservations, that is, their contract demands.

Offering two types of service in one tariff may have disadvantages. At the end of this NOPR we ask questions about whether this is so. If it is, a solution may be to put all jurisdictional transmission users on the same basis: The transmission provider would serve and charge all customers (including its own jurisdictional uses of the system) on the basis of how much transmission capacity they either use or ask for. That is, it would make the entire tariff either load-based or reservation-based. If we do reform the tariff to put all transmission users on the same basis, we believe that, for the reasons set out next, putting all on a reservation basis may be more consistent with the industry's direction in its competitive restructuring. We seek comment on whether this premise concerning reservation-based service is in fact correct.

First, reservation-based service appears to be more compatible with our new OASIS and the requirement that market participants know how much transmission is available for their use. In the OASIS Final Rule, we require public utilities to post electronically their available transmission capability, or ATC. They must do this by calculating total transmission capability and subtracting transmission capacity committed to other uses. It is relatively easy to subtract point-to-point service reservations, but there is no amount of transmission capacity explicitly reserved for network customers or for the transmission provider's own network uses.

The transmission provider is committed to having available enough transmission capacity to serve its native

[2] Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, Docket No. RM95–9–000, Order No. 889, FERC Stats. & Regs. ¶ 31,037 (1996) (OASIS Final Rule). This rule also is being published concurrently in the Federal Register.

[3] A ''nomination'' is a request; a ''reservation'' is a confirmed nomination that can be held or traded.

load and the loads of its network customers. But the transmission provider knows only the customers' historical loads, not their future loads. Although the customers (as well as the transmission provider itself) must forecast their loads, they may have no incentive to forecast accurately because the utility must meet all transmission needs for serving load regardless of the forecast. This requires the transmission provider to predict its future native load and that of each of its network customers in order to determine its ATC.

While this process can work reasonably well in a regime in which utilities make bundled generation and transmission sales to requirements customers, it may not work as well now that various kinds of power sellers and marketers are eligible for unbundled network service. The transmission provider may not have any good way to forecast the increases or decreases in the loads of customers that it has no obligation to serve. It seems appropriate to ask all transmission customers, including the transmission provider, to state explicitly how much transmission capacity they want set aside for their needs. In this way, they effectively would be making a capacity reservation. This would simplify the transmission provider's determination of ATC and make the information available on the OASIS.

Under a CRT approach, each transmission customer (including the transmission provider for its own uses) would have to state its transmission capacity needs, as in the current point-to-point tariff. The requirement that reservations be stated in order to be subtracted from total transmission capability would ensure that all customers are treated comparably without the transmission provider having to make forecasts only for some.

On the other hand, an argument can be made that the CRT approach may lead to an understatement of ATC. For example, in reserving transmission service, customers might base such reservations on an estimate of their maximum non-coincident peak (''NCP'') load. This conceivably could result in an understatement of ATC, because the diversity of customer loads at the time of the system peak would no longer be a relevant factor in determining ATC. The Commission requests comment on whether in practice this would be a problem and, if so, whether it can be remedied.

Second, a reservation-based tariff would put all jurisdictional transmission customers, including the transmission provider for its own jurisdictional uses, on the same basis. All customers would not only have to reserve transmission capacity but also would have to pay for the transmission capacity that they reserve.

It may be disadvantageous to have different bases for the pricing of two services in a tariff. For example, suppose a transmission provider has two nearly identical transmission customers. Each has a load of 50 MW, and each thinks its load next year could be as little as 40 MW or as much as 60 MW. However, one takes network service, and the other takes 60 MW of point-to-point service. Suppose these are the only customers on the system and they have coincident peak loads; if each actually uses 60 MW next year, each pays half the cost of the transmission system. But if each uses 40 MW, the point-to-point customer pays 60 percent of the cost[4] while the network customer pays only 40 percent.

Customers also may attempt to exploit to their advantage the different terms and conditions of the two services. As commenters in the Open Access proceeding pointed out, the many differences between capacity reservation-based (point-to-point) and load-based (network) services mean that transmission customers are treated differently. Having two services in a tariff may create an incentive for a customer to switch back and forth from one service to another in a way that may allow it to avoid paying a fair share of system costs. This would not be the case if all customers are served under a reservation-based (or load-based) tariff.

Third, a reservation-based approach may be a better basis for accommodating electric industry innovations and pricing reforms. The industry is in a period of rapid change, and many ideas are being considered for independent system operators (ISOs), regional transmission groups, regional power exchanges, generation divestiture, distribution company spin-offs, unified regional transmission ownership, regional transmission tariffs, megawatt-mile transmission pricing, marginal cost pricing, and congestion pricing, among other innovations. Innovations are being considered or implemented in such places as California, the Midwest, the large eastern power pools, and other places. Most proposals assume that all jurisdictional users of the transmission system will be treated alike.

Many commenters in the Open Access proceeding raised concerns that our pro forma tariffs with two separate services, one based on load and another based on capacity reservation, may be an obstacle to putting all transmission customers on the same basis and hence an obstacle to innovation. For example, the Commission would need to make special tariff accommodations to permit California public utilities to carry out the reforms mandated by the California Public Utilities Commission for an ISO, a regional power exchange, and congestion pricing. Although we have indicated that we are prepared to accept other tariff designs that further the goal of fostering robust competition in the bulk power market, the number of parties concerned with the traditional nature of our tariff suggests that our tariff may inhibit other parties from considering innovative industry structures and pricing policies.

This NOPR, among other things, indicates that the Commission is not committed to traditional tariff design. Further, it proposes a tariff design that supports calculation of ATC and treats all jurisdictional transmission users alike. We believe that the proposed CRT concept would provide a flexible base on which industry participants can build a variety of innovative tariff designs. We expect the CRT concept to be more compatible with various ISO and power pool pricing proposals than the traditional Open Access Final Rule tariff. We ask for comment on whether this is so. In addition, we request comment on whether there are other transmission capacity allocation methodologies (for instance, an ''all network service'' methodology) that, when compared to the two-service approach in the Final Rule, are more compatible with proposed and contemplated marketplace innovations.

In particular, we expect that a CRT would provide a better basis for regional flow-based transmission pricing. In the comments we received in the Open Access proceeding, a large number of industry participants stressed that the Commission should not codify contract path pricing in its Final Rule. As we explain more fully in the Open Access Final Rule, they were concerned that the proposed pro forma tariffs would codify the contract path approach to pricing. We explain in the Open Access Final Rule that this is not our intention; we continue to encourage the industry to explore solutions to regional loop flow problems through innovative regional flow-based pricing proposals.

It is unlikely that an efficient tariff for a large region would allocate some transmission costs on the basis of various subregional loads and other costs on the basis of capacity reserved over various multipath interfaces within

[4] This is based on a 60–MW reservation divided by the sum of the network loads and the capacity reservations at the time of system peak.

the region. Most regional tariff proposals would allocate costs on the latter basis alone, recognizing, of course, that the configuration of regional loads is a starting point for any load flow study. For this reason, we believe that the proposed CRT approach to tariff design may be more compatible with the intent of some in the industry to move to flow-based pricing than a tariff that combines services based on usage and reservations. We ask for comments on whether this is the case. In addition, we ask for comment on whether there are other non-CRT approaches that may be more compatible with flow-based pricing.

Fourth, as discussed in the Open Access Final Rule, load-based network service generally cannot be resold. This reduces the amount of transmission products and services that can enter the secondary market. As a result, the secondary market could be thinner and less effective as a risk management tool for market participants. In addition, independent generators and marketers could be hampered in making efficiency-enhancing transactions that do not involve a load-serving entity, such as trading power between generators in different market centers. The Commission seeks comments on whether a capacity reservation service or some other alternative to the two-service approach in the Final Rule would better allow market participants to freely make efficient deals that involve combining transmission entitlements with power products in new and creative ways.

Fifth, we believe that additional comments should be received on whether the goal of unbundling transmission and generation services can be fully achieved under load-based network service. It would appear that transmission service would be fully unbundled from generation service under a CRT because the generation and transmission products are reserved and used independently. For example, reservations for flexible grid use, including interface capacity, could be held independently of load. In addition, generation resources and load would not need to be designated as under the network service; a transmission customer would have to pay for the capacity it reserved at PODs and PORs, but it would not have to designate any resources or loads.

Sixth, a capacity reservation approach may facilitate transmission planning. Under a CRT, all wholesale transmission users and unbundled retail transmission customers would be required to specify and pay for all of their transmission needs, including capacity needed for contingencies. The costs of contingency margins needed by only some users would not be allocated to all users of the grid. A CRT would allow each customer flexibility in managing its own risk, *e.g.,* a customer could factor reasonable reserve margins into its reservation for contingencies. This approach may be consistent with some innovative proposals that seek to accommodate customer-driven transmission expansion, in addition to traditional utility-planned transmission expansion.

Finally, some commenters in the Open Access proceeding encouraged us to treat the retail function of a public utility transmission provider as a separate wholesale customer for purposes of the transmission tariff. While we do not require this in the Open Access Final Rule, we propose here that the transmission used on behalf of the transmission provider's bundled retail native load be *nominated and reserved* in the same way as all other transmission service.[5] Requiring the same reservation system for all transmission capacity needs would help to assure that all uses of the transmission system are treated in a comparable, non-discriminatory manner. We seek comment on whether the retail function of a public utility transmission provider should be treated as a separate wholesale customer for purposes of the CRT tariff.

V. Capacity Reservation Service

A. Discussion

The Commission's CRT proposal is as follows. Each public utility subject to the Open Access Final Rule would be required to file a CRT no later than December 31, 1997. Under the CRT, which would replace existing transmission tariffs, all firm transmission users, including the transmission owner on behalf of its wholesale requirements and bundled retail customers, would nominate and reserve transmission capacity; they would nominate and reserve firm rights to receive specific amounts of power at specific grid PORs and to deliver specific amounts of power at specific grid PODs. PORs could include interconnections with other systems or generator bus bars. PODs could include interconnections with other systems or substations where the transmission provider's transmission and distribution systems are connected. Reservation holders could flexibly schedule power among some or all of their PORs and PODs within their reservation limits and could reassign their reservations. Thus, capacity reservation service could be used both for point-to-point types of transactions and in a network manner (integration of a set of generating resources with a dispersed load).

The capacity reservation approach would be based on the flexible point-to-point service in the Open Access Final Rule. A customer could specify a single POR and a single POD, or it could reserve service from multiple PORs to multiple PODs. The transmission provider would set aside sufficient transmission capacity to satisfy its firm reservation needs for any potential combinations of power receipts and deliveries among the designated receipt and delivery points.

An entity with dispersed generation and load could use CRT service to dispatch its generation economically within its capacity reservation. When one generating unit is ramped down, the customer could ramp up another generating unit located at another designated receipt point. The flexibility to serve load when the transmission customer is using less than its capacity reservation would be the same as under Final Rule network service. CRT service could also be used for simple point-to-point transactions if the customer does not want or need much flexibility.

Under a CRT, a customer also could have the flexibility to rearrange, or modify, its firm reservation to deal with unforeseen circumstances. Such a rearrangement could be accomplished as long as the customer's capacity reservation is not exceeded and firm transmission capacity is available. The flexibility of the proposed CRT service would not be unlimited, however. For example, a transmission customer might have very little flexibility to modify its reservation on a firm basis to accommodate an unanticipated dispatch pattern when the grid is operating at or close to capacity. Under such conditions, modifications likely would infringe on other firm reservations. To manage this risk, the customer would have two basic options. One would be to take non-firm transmission or ancillary service on an as-available basis (and potentially pay opportunity costs) when the need to alter the planned operation arises. The other option would be to subscribe to sufficient firm capacity in advance so as to build in the desired operating flexibility. While either option would have financial risks, all jurisdictional transmission customers would have the same opportunity to manage this risk, since the transmission service would be the same for all users.

[5] As discussed below, this is not the same as requiring bundled retail customers to *take* service under the CRT.

Under a CRT, all unbundled transmission service in interstate commerce, including unbundled retail service, would be taken under the tariff unless the Commission in an individual case determined otherwise (as discussed in the Open Access Final Rule in Section IV.I). The rates, terms, and conditions for unbundled transmission service would be in accordance with the tariff. In addition, all public utilities would nominate and reserve firm transmission service under the tariffs, including nominating and reserving transmission used for native load (*i.e.*, bundled wholesale requirements and bundled retail customers). This means that nominations and reservations would have to be made for specific receipt and delivery points for *all* firm transmission services. The purpose of this requirement would be that it may better ensure comparability. Moreover, the requirement for utilities to hold reservations on behalf of bundled wholesale and retail customers would be consistent with our responsibility under FPA section 213(b) to make information available about ATC and transmission constraints. The physical quantities of transmission service available to unbundled users cannot be measured accurately as long as the physical quantities used for bundled service are not measured in the same way.

However, we wish to emphasize that we are not proposing to set the rates, terms or conditions for the transmission component of bundled retail service. Nor would we determine the amount of capacity to be reserved for retail load. Traditional ratemaking prerogatives of state commissions would be unchanged by this nomination and reservation requirement. If the CRT is adopted, the Commission would allocate transmission costs based on the sum of all reservations for wholesale customers, unbundled retail customers, and bundled retail customers. State commissions could adopt a similar approach; however, they would remain free to use an inter-jurisdictional allocation formula of their own choosing, just as they may now. We note that in the Open Access Final Rule we have provided for procedures to facilitate jurisdictional line-drawing regarding cost allocation, and for deference to state recommendations. Therefore, we do not expect significant conflicts.

Under a CRT, a public utility would have an opportunity to recover all of its transmission fixed costs, just as it does today. While it is possible that the federal and state allocations could add up to less or more than 100 percent of the utility's fixed transmission costs, that is a risk that a utility faces anytime it is subject to the rate jurisdiction of more than one regulatory authority. Moreover, we would work with state commissions to develop compatible cost allocation procedures and to minimize the possibility of any over- or under-recovery of transmission costs.

B. Proposed Principles

A capacity reservation tariff might have terms and conditions very much like those for point-to-point service in the Final Rule tariff. These would need to be modified to accommodate former network service customers. It is premature to specify detailed terms and conditions of capacity reservation service in advance of the comments and technical conference. However, we propose certain general capacity reservation tariff principles for comment.

1. *Purpose of Reservation Service*

Transmission products and services should be provided on an open access, comparable basis. In order to ensure comparability, transmission service should be nominated and reserved on a non-discriminatory basis. Transmission for wholesale sales of electric energy should be made available on an unbundled basis.

2. *Basic Service Concept*

All firm transmission service would be reserved, and all reserved service would be firm service. Reservations of transmission capacity should permit the customer to receive up to a specific amount of power into the grid at specified PORs, and to deliver up to a specific amount of power from the grid at specified PODs, on a firm basis. Individual PORs and PODs need not be ''paired'' with each other. The customer's capacity reservation would be the higher of either (1) the sum of the reservations at all PORs or (2) the sum of the reservations at all PODs. All nominations for a capacity reservation would be evaluated using the same standard; for example, the utility could apply a feasibility criterion that states that the grid must be able to accommodate the scheduled use of all capacity reservations simultaneously.

3. *Use of Capacity Reservations*

A customer with a capacity reservation could use the reservation to deliver or receive any type of power product (such as firm or non-firm power). That is, use of the capacity reservation should not be restricted to particular power products. Any such restriction would be inconsistent with unbundling. This would allow the capacity reservation holder to combine transmission and power products in any way that satisfies its needs.

4. *Applicability to All Customers*

Capacity reservations for all firm transmission service would be made under the CRT, including reservations nominated on behalf of the transmission provider's bundled wholesale and retail customers. This would make it possible to allocate capacity and costs comparably among all transmission users. This would not require the unbundling of the transmission component of bundled retail rates or affect state authority with regard to the rates, terms, and conditions of service to bundled retail customers.

5. *Application of Penalties for Overuse*

Any charges for exceeding capacity reservations should be non-discriminatory. If a CRT penalizes use in excess of reserved amounts, these penalties should be applied comparably to all reservations. Any dispositions of penalties assessed against the utility for violating bundled retail capacity reservations would be under the state commission's ratemaking authority. If penalties are not authorized by the state commission's ratemaking authority, the Commission would not authorize recovery of such penalties from other transmission customers.

6. *Standard for Accepting Nominations*

A nomination for a capacity reservation would be accepted if the transmission provider determines that it can be reliably accommodated without infringing on other firm reservations. If transmission capacity expansion is needed and approved by state siting authorities, a nomination should be accepted if the nominating customer is willing to pay its appropriate share of the cost of the expansion.

7. *Non-firm Transmission Service*

In addition to reserved firm service, transmission providers would offer non-firm transmission service. Non-firm service could be provided from transmission capacity not scheduled by customers with reservations or from capacity that is not previously reserved. Non-firm service would be allocated to the highest valued use by opportunity cost pricing as described in the Open Access Final Rule or by some other pricing consistent with the Commission's Transmission Pricing Policy Statement.

8. *Open Season for New Facilities*

We would anticipate requiring a transmission provider to publicly announce its plans for capacity expansion projects to allow market participants to reserve capacity. Participants would pay an appropriate share of the costs of the project. All market participants would be treated comparably in securing additional transmission capacity reservations when the grid capacity is expanded.

9. *Cost Allocation and Pricing*

The fixed costs of the transmission network would be allocated among reservation holders on the basis of their capacity reservations. Rates would be designed to recover these costs and would be revised from time to time to reflect changes in the level of fixed costs or changes in reserved amounts. In this way, transmission providers would have an opportunity to fully recover their fixed costs. Transmission providers would be expected to propose specific mechanisms for recovering fixed costs from transmission customers.

10. *Standardized Products and Priority Protocols*

Just as the Commission has required under the Open Access Final Rule tariff, the CRT would offer standardized transmission products and services, defining reserved and non-reserved transmission service and setting reservation priorities and curtailment protocols. This would reduce uncertainty and facilitate the trading of any transmission capacity in a secondary market. Such trading can be an important tool in price discovery and risk management.

11. *Service Modifications*

Customers with a capacity reservation would be allowed to modify their capacity reservations at no additional charge if the modification can be accommodated without infringing upon any other firm capacity reservations. Modifications should not result in the customer's capacity reservation being exceeded. Modifications could include reallocation among the customer's already specified receipt and delivery points or reallocation from existing to new receipt and delivery points.

12. *Scheduling Flexibility*

Customers with capacity reservations would be given the option of scheduling (using) less than their full capacity reservation at each POR or POD. In addition, the transmission provider also could offer an ''obligation'' type of capacity reservation under which the customer would be required to use all of the capacity it has reserved.

13. *Reassigning Reservations*

Customers would be allowed to reassign their reservations to other entities eligible to take service under the CRT at no additional cost, subject to certain limitations, such as those in the Open Access Final Rule point-to-point tariff provisions.

14. *Opportunity Cost Pricing*

Opportunity cost pricing would still be an option under a capacity reservation service. Under a CRT, a holder of a capacity reservation would not pay opportunity costs for use of its own capacity when the utility encounters a transmission constraint; instead, it would be eligible to receive opportunity cost payments if it did not use its full capacity reservation across the constrained interface. In contrast, a customer seeking a capacity reservation or using non-firm service might have to pay opportunity costs.

15. *Planning Obligation*

Each market participant would be responsible for planning its own transmission needs. The transmission provider would not be responsible under Federal rules for planning the CRT nominations of others, even relatively small customers. Transmission providers, of course, would be free to enter voluntary arrangements to perform this task, or they may be required to do so under state laws. The Commission would consider approving negotiated rates and conditions between a small customer and a transmission utility that reflect different risks accepted by each party when one plans for the other.

VI. Questions

In addition to the questions discussed above, the Commission also seeks comments on the following questions:

1. What are the advantages and disadvantages of having two services in one tariff?

2. What are the advantages and disadvantages of having all transmission users on a load-based network service tariff? Are there ways of overcoming the disadvantages without moving away from network service?

3. Does network service provide any transmission use that could not be provided under a CRT?

4. Is the CRT or a network approach better suited to encouraging efficiency-enhancing transactions and encouraging wholesale power markets in which the greatest number of sellers have a chance to compete? Are they equally-suited to achieving these goals?

5. The proposed rule would require that all transmission uses, including bundled retail service, be reserved. Is this appropriate? The Commission intends that bundled wholesale and retail load would have reservation priority and seeks comments on how best to achieve this. Is it appropriate or necessary to have federal rules regarding such matters as physical scheduling and reservation priority for bundled retail load as well as for other transmission customers? How can transmission service for bundled retail load be separated from transmission service for others and how would such a separation be implemented?

6. Would a CRT requirement by the Commission facilitate or hinder any of the industry's current restructuring efforts?

7. Would a CRT facilitate or hinder any of the innovative transmission pricing approaches now being considered by the industry? Specifically, would it accommodate flow-based pricing that does not depend on a contract path?

8. Should nominations for longer-term capacity reservation receive priority over those for shorter terms? Are there other ways to allocate capacity nominations? Would an initial open season, with bundled wholesale and retail load priority, be appropriate?

9. How should points of receipt and points of delivery be defined? Is the distinction between transmission and distribution relevant in determining eligible points?

VII. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA)[6] requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities. We note, if this proposed rule is adopted, only public utilities that are subject to the Open Access Final Rule will have to file CRTs. In other words, the proposed rule would be applicable to public utilities that own, control or operate interstate transmission facilities, not to electric utilities *per se*. Almost all public utilities that own, control or operate interstate transmission facilities do not fall within the RFA definition of small entities.

[6] 5 U.S.C. §§ 601–612.

In *Mid-Tex Electric Coop., Inc.* v. *FERC*,[7] the court accepted with the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term ''small entities'' as defined in the RFA,[8] the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP).[9] The CWIP rules applied to all public utilities. The proposed rule in contrast would apply to only those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule. Further, the Commission expects that public utilities for good cause shown could seek waivers of the proposed rule's requirement, just as they are able to seek waiver of the Open Access Final Rule.

Because: (a) Virtually all of the utilities that would be subject to the proposed rule are not ''small entities'' as defined in the RFA; and (b) the proposed rule will make adequate provision, through allowances for waivers, for mitigation of the effects of the rule, the Commission certifies that this proposed rule will not have a significant economic impact on a substantial number of small entities.

VIII. Environmental Statement

The Commission concludes that promulgating the proposed rule would not represent a major federal action having a significant adverse impact on the human environment under the Commission's regulations implementing the National Environmental Policy Act.[10]

IX. Information Collection Statement

The Office of Management and Budget's (OMB) regulations [11] require that OMB approve certain information and recordkeeping requirements imposed by an agency.

The information collection requirements in the proposed rule are contained in FERC–516 ''Electric Rate Filings.'' The Commission uses the data collected in this information collection requirement to carry out its regulatory responsibilities under Part II of the Federal Power Act. The Commission's Office of Electric Power Regulation uses the data to review electric rate filings.

The Commission is submitting notification of this proposed rule to OMB. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 (Attention: Michael Miller, Information Policy and Standards Branch, (202) 208–1415). Comments on the requirements of this proposed rule can also be sent to the Office of Information and Regulatory Affairs of OMB (Attention: Desk Officer for Federal Energy Regulatory Commission).

X. Public Comment Procedures

The Commission invites comments on the proposed rule from interested persons. An original and 14 copies of written comments on the proposed rule must be filed with the Commission no later than August 1, 1996.

In addition, commenters are requested to submit a copy of their comments on a 3½ inch diskette formatted for MS–DOS based computers. In light of our ability to translate MS-DOS based materials, the text need be submitted only in the format and version in which it was generated (*i.e.*, MS Word, WordPerfect, ASCII, etc.). It is not necessary to reformat word processor text to ASCII. For Macintosh and Macintosh-based users, it would be helpful to save the documents in Macintosh word processor format and then to write them to files on a diskette formatted for MS-DOS machines. All comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, and should refer to Docket No. RM96–11–000.

All written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's public reference room at 888 First Street, N.E., Washington, DC 20426, during regular business hours.

XI. Technical Conference

The Commission intends to convene a technical conference for two days in September 1996 at the Commission's office, 888 First Street NE., Washington, DC 20426, at a date and time to be announced. The first day of the technical conference will address the issue of whether the Commission should require CRTs. The second day will address the issue of how to implement any such requirement.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements

By direction of the Commission.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission proposes to amend part 35, chapter I, title 18, Code of Federal Regulations, as set forth below.

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Section 35.28 is revised to read as follows:

§ 35.28 Non-discriminatory open access transmission tariffs.

(a) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a capacity reservation tariff of general applicability for transmission services, including ancillary services, over these facilities consistent with the requirements of Order No. ____, (Final Rule on Open Access Capacity Reservation Tariffs). Subject to the exception in paragraph (b) of this section, such tariff must be filed no later than the date on which the Commission accepts for filing any agreement under which such public utility would engage in a sale of electric energy at wholesale in interstate commerce, or any agreement under which such public utility would engage in the transmission of electric energy in interstate commerce.

(b) If a public utility owns, controls or operates facilities used for the transmission of electric energy in interstate commerce as of July 9, 1996. it must file a capacity reservation tariff of general applicability for transmission services, including ancillary services, over these facilities consistent with the requirements of Order No. — (Final Rule on Open Access Capacity Reservation Tariffs) no later than December 31, 1997.

(c) Any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or

[7] 773 F.2d 327, 340–343 (D.C. Cir. 1985) (*Mid-Tex*).

[8] The RFA defines a ''small entity'' as ''one which is independently owned and operated and which is not dominant in its field of operation.'' *See* 5 U.S.C. 601(3) and 601(6) and 15 U.S.C. 632(a)(1) (definition of ''small business concern'').

[9] *Mid-Tex*, 773 F.2d at 340–43.

[10] *See* 18 CFR 380.4(a)(15) (categorically excluding electric tariff filings under sections 205 and 206 of the FPA from the obligation to prepare an environmental assessment or an environmental impact statement).

[11] 5 CFR 1320.12.

unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the tariff filed pursuant to this section.

[FR Doc. 96–10692 Filed 5–09–96; 8:45 am]

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federal register

Friday
May 10, 1996

Part III

Environmental Protection Agency

Permits Improvement Team Concept Paper on Environmental Permitting and Task Force Recommendations; Availability; Notice

ENVIRONMENTAL PROTECTION AGENCY

[FRL–5501–7]

Notice of Availability of Permits Improvement Team Concept Paper on Environmental Permitting and Task Force Recommendations

AGENCY: Environmental Protection Agency.

ACTION: Final draft of Permits Improvement Team's Recommendations.

SUMMARY: The PIT was formed in July 1994 to evaluate the Agency's permitting programs, both delegated and administered directly, and develop recommendations to improve the effectiveness and efficiency of the permitting process. The PIT is composed of representatives from EPA Headquarters and Regional Office and state, tribal and local permitting agencies. The PIT held numerous stakeholder meetings to solicit input on the most critical permitting issues and to obtain feedback on the initial recommendations.

Although significant input on the PIT's recommendations has been received through our stakeholder meetings, a brief final review by appropriate Federal Advisory Committee Act (FACA) organizations (Common Sense Initiative, National Environmental Justice Advisory Council and Federal Facilities Environmental Restoration Dialogue Committee) is being provided. This is being done to ensure that the recommendations are not inconsistent with the efforts of these Agency advisory groups. After making any changes based on this review, the PIT recommendations will be submitted to Administrator Browner for her consideration. Should she endorse the recommendations, implementation will commence. Stakeholders will continue to be involved in specific permit reform efforts.

The PIT Concept Paper on Environmental Permitting and Task Force Recommendations follows this notice. In addition, the document can be obtained via the Internet at 'gopher://gopher.epa.gov' or 'http://www.epa.gov'. After reaching either of these Internet sites, locate the search function and type 'Permit Improvement Team' to locate the Concept Paper on Environmental Permitting and Task Force Recommendations. A copy can also be obtained by writing to the Permits Improvement Team, Mail Stop 100, 2890 Woodbridge Ave., Edison, NJ 08837.

If an organization would like to discuss the PIT recommendations a meeting can be arranged, provided funding is available in the Agency's budget. Contact Lance Miller, PIT Executive Director at the above address to arrange a meeting.

Dated: April 19, 1996.

Elliott P. Laws,

Designated Federal Official.

PERMITS IMPROVEMENT TEAM FINAL DRAFT OF CONCEPT PAPER ON ENVIRONMENTAL PERMITTING AND TASK FORCE RECOMMENDATIONS

April 1996

CONCEPT PAPER ON ENVIRONMENTAL PERMITTING

I. Introduction

A. Purpose of the Concept Paper

Over the past 25 years, EPA has continually searched to find the best ways to protect the environment. Among the most successful methods have been EPA's programs requiring industrial and municipal facilities to obtain permits to control their pollutant emissions [1] to the air, land and water. Programs such as New Source Review for air emissions, National Pollutant Discharge Elimination System (NPDES) for water discharges and the Resource Conservation and Recovery Act (RCRA) for hazardous waste management have in many ways reduced the negative impacts of industrial and municipal facilities on human health and the environment.

But numerous environmental challenges remain. Perhaps the greatest challenge for EPA today is to answer the public demand for *more* environmental protection at *less* cost. This demand of ''more for less'' requires EPA to examine both the philosophy and practice of its permitting systems, to determine how they can be made to function more effectively while at the same time decreasing costs for environmental agencies and the regulated community.

This concept paper seeks to resolve these concerns by establishing a revised approach to environmental permitting: public performance-based permitting. This approach incorporates two concepts; one, the establishment of a defined level of performance to be achieved by the permittee and two, providing the public with the necessary information so they can monitor the permitting process and compliance of permitted facilities. Once the final draft of this concept paper has been completed and approved (following the incorporation of additional comments), it will serve as a statement of official EPA policy on environmental permitting. As such, it will be used by EPA permit programs as guidance. EPA Program offices affected by these changes will need to develop plans that outline what they must do to implement these principles (e.g., policy, regulatory or process changes) consistent with statutory requirements. Theses plans could take the form of program specific strategic plans that would include short and long-term goals for moving the public performance-based permitting concepts forward. It is important to note that some EPA programs, such as NPDES permitting, are already applying many of these principles, and therefore may have fewer changes to make.

Other environmental permitting programs, such as those of state, tribal or local governments, are strongly encouraged to adopt these principles where appropriate.

B. EPA's Relationship With State, Tribal and Local Environmental Agencies

Before discussing the principles of a modified permitting system, it is important to understand the context in which these principles would be carried out. Rather than issuing most permits itself, EPA generally has established programs to authorize state, tribal and local permitting authorities, to perform most of the permitting. Recently, EPA and the states signed an agreement, the National Environmental Performance Partnership System, aimed at making EPA oversight of states less uniform and prescriptive and more based on performance, so that states with more effective programs and proven environmental results may receive less oversight. A similar approach is being developed for tribes. This concept paper follows the principles of the new EPA/state relationship, with the goals of making EPA permitting systems more performance-based and providing authorized permitting authorities more flexibility to find the best approaches to permitting and data management. The principles in this paper, therefore, should be understood as approaches that EPA would like to encourage through flexibility and assistance to state, tribal and local governments, and not as any kind of new mandates. A key aspect of that assistance is the provision of information from EPA databases. A comprehensive effort to upgrade the quality and breadth of these databases is needed. Some of the individual Task Force recommendations that follow this paper identify specific projects to improve the Agency's delivery of

[1] The terms ''emission'', ''release'' and ''discharge'' are used interchangeably in this paper.

information. In addition, specific changes to the permitting system need to be developed through continued dialogue with state, tribal and local environmental agencies and other stakeholders.[2]

C. Permits Improvement Initiatives

While EPA and many other environmental agencies have taken, and are taking, specific actions to improve their permitting systems, there is also a need to re-examine EPA's overall approach to permitting. Toward this end, the Permits Improvement Team (PIT) was founded by EPA's Administrator in July 1994 to comprehensively examine the permit reform efforts going on around the country and determine how, taking the best of these efforts, EPA's overall approach to permitting could be improved. (A compilation of over 100 environmental agency permitting reform projects, entitled ''The Inventory of USEPA/State Permit Improvement Initiatives'' can be accessed via the internet at 'gopher://gopher.epa.gov' or at 'http://www.epa.gov'. After reaching either of these internet sites, locate the search function and type 'Permit Improvement Team' to locate the inventory. A hard copy of the inventory can be obtained by calling 908–321–6782.)

D. Public Performance-Based Permitting

The purpose of permitting is to establish the level of performance needed by facilities or individuals to protect human health and the environment. To do so, EPA has in some cases set performance standards, determined the technical means by which facilities must comply with these standards, and then required monitoring and inspection to assure their compliance. In some instances, standards were highly prescriptive (including detailed technology or management requirements) that eliminate or severely restrict alternative approaches to achieving compliance. In other cases EPA bases a standard on a technology, which can be viewed by the regulated community as the technology of choice.

It is the contention of this paper that too much time and resources are spent reviewing the *technical means* by which a permittee will comply with permit conditions. While detailed technical reviews were warranted 25 years ago, sufficient progress has been made in verifying technology and increasing corporate environmental responsibility that it is now appropriate to re-evaluate this approach. In instances where technologies are new or unique, detailed technical review may still be warranted; in circumstances where proven or verified technology is being permitted, however, such level of review may be inappropriate. Conducting detailed technical reviews for off-the-shelf technologies has resulted in several negative consequences:

- Permitting agencies are overloaded with routine detailed paperwork to review. This takes time away from other activities, as verifying the equivalency of performance for innovative technologies, causes permit actions to take an unacceptable amount of time, and prevents a more logical and beneficial ordering of priorities. In addition, the excessive focus on the *means* of compliance distracts attention from evaluation of progress on the *end* of improving environmental conditions.
- The regulated community, in addition to sometimes being burdened by unwarranted paperwork, a slow permitting process and unnecessary economic hardships, is in some cases not provided the flexibility—or any incentives—to seek the kind of technological innovations which could *prevent* pollution at its source, and/or provide better environmental results at lower cost.
- The permitting process is largely focused on technical issues, sometimes, beyond the grasp and interest of the general public. The permitting agency and permittee can spend much time grappling with these issues, while the public is usually excluded until such a time when these issues have been resolved through the writing of a draft permit. The public's ability and opportunity to judge the permit process and results can thus be unduly limited.

In order to remedy this situation, this paper proposes a permitting approach called public performance-based permitting, or P3. The essence of this approach is to shift the focus of environmental permitting towards the measurement and assurance of performance, while providing flexibility as to *how* a permittee will meet performance standards. The focus of this system will not simply be performance, but performance within a public arena: to the extent possible and appropriate, the public should be involved in the setting of performance standards and the measurement and judgement of performance. It is recognized that the existing environmental statutes may limit EPA's latitude in fully implementing this approach. As EPA seeks changes to its various permitting programs in accordance with this approach, specific legislative barriers will be identified. As opportunities develop to address these barriers, specific legislative changes will be proposed.

The P3 principle includes three different types of performance. The existing permitting programs each contain elements of this principle. The objective of the permitting programs will be to more fully implement each type of performance.

1. Environmental results: How are permitted activities actually affecting the environment? To improve knowledge and understanding of this performance factor, this paper proposes that permitting agencies increase ambient (environmental) monitoring as a permit condition in selected permits, while comparatively reducing other emissions monitoring and reporting requirements. Ambient monitoring results shall be reported to the public in understandable terms. Ambient monitoring would not eliminate individual facility monitoring requirements.

2. Facility compliance: How well are permitted facilities complying with their permits over time? To increase the rates at which facilities comply with their permit conditions, permitting agencies should (1) establish reporting requirements based on a facility's level of compliance (e.g., reduce reporting for facilities with good compliance records) and potential impact of an activity, (2) create incentives for pollution prevention and technological innovation, and (3) provide compliance assistance to facilities that are making good-faith efforts but finding it difficult to comply (e.g., small businesses and local governments). Furthermore, compliance data will be put in understandable terms and made available to the public.

3. Agency performance: How good a job are EPA and other environmental permitting agencies doing? To ensure that they continue to protect the environment in the most effective and efficient ways possible, this paper recommends that EPA devise methods to measure the performance of permitting systems and to continually improve these systems based on performance data received. These methods shall be provided for the use of state, tribal and local environmental agencies as well. Information on the performance of all permitting agencies should be publicly reported in understandable terms.

[2] The term stakeholder(s) is used in this paper to refer to all groups interested in environmental permitting, including environmental, community and environmental justice groups, regulated entities, and state, tribal and local permitting agencies.

The proposals for these three types of performance are detailed in the following sections. But first, it is necessary to discuss in more detail the importance of public participation in the approach to permitting specified in this concept paper.

Traditionally, permitting agencies have limited public participation to public comment periods and hearings at the latter stages of the permit process. This concept paper sets forth a more open process that provides the public opportunities for earlier and more meaningful participation, within the context of the requirements specified in federal and state laws. This model is inspired by some recent initiatives in public participation, including EPA's RCRA Expanded Public Participation rule and the Chemical Manufacturing Association's (CMA) Responsible Care Program.

These initiatives are based on the concept of direct reporting of information to the public early in the permitting process and in understandable terms. In addition to increasing public awareness regarding facility operations, these programs can serve as a powerful incentive for facilities to reduce their toxic emissions, so as to avoid arousing public concern. P3 would extend these concepts to the public reporting of ambient monitoring results, facility compliance data and information on how well EPA and permitting agencies are performing.

Furthermore, an effective permitting process (for individual permits) requires that the public be involved early and intimately enough that their needs and concerns may be incorporated into permits and other aspects of facility and/or agency policy. Such opportunities can defuse the kinds of adversarial relationships which otherwise may slow and obstruct the permitting system with, for example, lawsuits or permit appeals.

To address these types of concerns, the CMA established its Responsible Care program. Under this program, chemical plants are encouraged to establish community advisory panels, through which the facility and members of its surrounding community can establish a continuing dialogue. The Departments of Defense and Energy have developed similar programs to encourage community participation in their environmental projects. Such forums allow the public and the facility new opportunities to educate each other on their respective needs and concerns, and to jointly resolve differences on environmental issues. EPA will encourage the development of community advisory panels at more facilities, by facilitating the establishment of similar committees in situations where the public and regulated community determine it would be beneficial.

Public performance-based permitting is designed to change the relationships among permitting agencies, permittees and the general public. The permitting process is currently often burdened with mistrust and adversarial relationships among all three of these parties. If these relationships can be rebuilt on a basis of trust, partnering, accountability and cooperation, the most serious obstacles to an effective and efficient permitting system will have been removed. (See Figure I)

The PIT specifically notes that there are regulatory or statutory barriers to some of the approaches listed below. The Agency's ability to implement each of these options under current law would need to be investigated further as these options are developed in more detail.

II. Environmental Results

The ultimate measure of the performance of EPA's environmental permitting systems is the condition of the air, land and water. Current permitting systems focus primarily on gathering information about permittees' compliance, but comparatively little information is gathered on the actual effects of permitted activities on human health and the environment. To a large extent, environmental permitting systems also lack the flexibility to restructure and rearrange their priorities in response to such environmental performance data, since they are often set up to issue individual permits based solely on the potential impacts of each facility. However, changes are being proposed in this area as permitting authorities consider ecosystem and community based approaches to permit issuance.

Yet in order to answer public demands for *more* environmental protection at *less* cost, there is a need to determine how to focus more resources on the activities producing the greatest environmental impact, while divesting from activities of lesser significance. To do so effectively, better information is needed on the effects industrial and municipal activities are actually having on the air, land and water.

This should be accomplished through, for example, an increase in the use of ambient monitoring as a permit condition. Practically speaking, this cannot be done overnight. EPA needs to research how to perform ambient monitoring in a cost-effective manner, how to collect useful data and how to trace pollution found through such monitoring back to the source(s). Different media present varying challenges: air monitoring, for example, is particularly complex. It might be beneficial to work on these issues in a multi-program team with Office of Research and Development (ORD) support.

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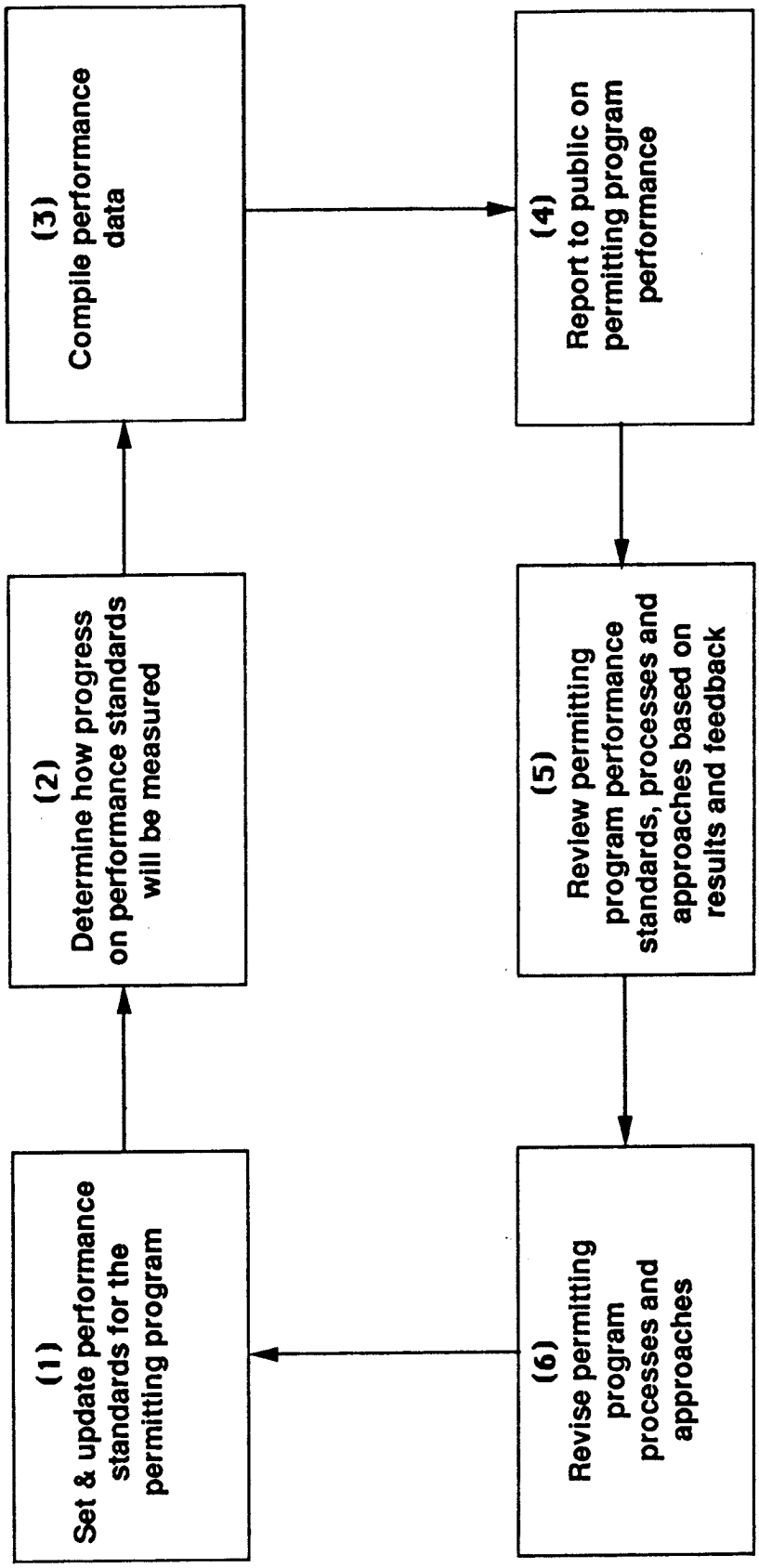
Figure II:
Continuous Performance Improvement System for Permitting Programs



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Despite these challenges, some programs are already beginning to achieve these objectives. The Greater Houston Partnership, for example, is a voluntary program under which Houston-area refineries have set up an air monitoring network. In the short term, EPA will encourage and set up more such pilots and feed all results into a study of how to run effective ambient monitoring programs. These pilots should cover each media (air, surface water and ground water) jointly or separately, and some of the pilots should incorporate the concept of involving the community in monitoring, facilitated by experts from government or the private sector.

At the same time, it is important *not* to increase the information-gathering and reporting burden on permitted facilities. On many occasions, the regulated community has raised concerns about having to meet duplicative or counter-productive compliance monitoring, reporting or record-keeping requirements. In exchange for increasing ambient monitoring requirements, therefore, EPA shall concurrently identify and eliminate other compliance information requirements. The Office of Enforcement and Compliance Assurance and the Program offices, in consultation with stakeholders, will conduct thorough program reviews that rank compliance monitoring, reporting and record-keeping requirements according to the best estimate of their actual value to the environment and to determine where different media requirements for compliance information duplicate and/or conflict with one another. The reviews should be followed by proposals and schedules for permit programs to streamline reporting requirements.

This approach is an element in several other EPA initiatives. In response to a Presidential initiative, EPA is examining how it can reduce paperwork requirements by 25%. This effort should be a major portion of the reviews discussed in the preceding paragraph. In addition, EPA's ''one-stop reporting initiative'' aims to streamline reporting requirements, for example by replacing separate facility identification codes used by different EPA programs with a single facility identifier.

Increasing ambient monitoring while decreasing other compliance information requirements at the source would allow permitting agencies to prioritize permitting information requirements based on real environmental impacts. But permitting agencies should be encouraged and allowed to take this idea one step further, and prioritize which facilities will receive full-fledged individual permits and which facilities can receive general (non-individual) permits or no permit at all, based on certain conditions or levels of emissions (this would require statutory amendments for some programs). The better ambient information becomes, the more precisely permitting agencies can and should gear environmental permitting systems to the most significant risks to the environment. This could entail protection of high quality areas as well as focusing on areas where environmental standards are not being achieved.

One major reform being developed by the PIT is to establish criteria to determine when individual permits are needed and when they could be replaced with types of permits requiring less administrative oversight and cost, without any impact to the environment. Such alternatives to individual permits include general permits, permits-by-rule, hybrid permits, and conditional and de minimis exemptions from permitting. Criteria developed by the PIT's Alternatives to Individual Permits Task Force include:

- Issue permits only where there is a real or potential adverse environmental impact and the regulatory agency needs to be involved (add value) in developing proper controls. This would require revision to certain environmental statutes.
- Issue *individual* permits only where there is a potential for significant environmental impact or high degree of variability in regulatory requirements at individual facilities.

It is important that the public be involved in the development and implementation of any alternatives to individual permits, and that adequate compliance and enforcement programs be put in place where alternatives to individual permits are developed.

In the long term, and in conjunction with the pilots and research discussed above—and recognizing the legal constraints that may exist—EPA Program offices will revise policies and regulations to provide state, tribal and local permitting agencies more flexibility and guidance to: increase ambient monitoring, reduce end-of-pipe/stack monitoring and reporting requirements, adjust databases to focus on ambient data, and tier permitting systems based on the actual environmental impacts of different types of facilities and activities. Some programs (e.g. OW) are already developing guidance for reducing reporting and monitoring requirements.

III. Permittee Compliance

A. Hierarchy of Permitting Standards

While permitting systems need to be better geared towards actual environmental impacts, as discussed above, they still must include sufficient monitoring to determine permittee compliance. The key is to make permitting systems *less prescriptive* and *more performance-based*, or in other words, to continue to tell a permittee *what* standards to achieve, but to no longer mandate, in most cases, *how* they are to achieve them.

This more flexible approach is designed to:

- Help the environment by encouraging pollution prevention;
- Help permittees by giving them the opportunity to develop more cost-effective (and equally or more environmentally effective) approaches to pollution control and prevention; and
- Help permitting agencies by allowing them to shift resources from extensive engineering and paperwork reviews to a focus on ambient monitoring, standard setting, compliance assistance and enforcement.

Permitting based on performance standards rather than on technology or management requirements is not a completely new idea. EPA's NPDES program, for example, currently uses such an approach to a large extent. Performance-based permitting will now be the preferred approach, wherever feasible and appropriate, for all of EPA's permitting programs, and State, tribal and local governments will be provided the flexibility and guidance to implement similar approaches. Programs not using performance-based permitting will need to justify why that approach is not appropriate (e.g., see Underground Injection Control (UIC) example below).

Thus, EPA programs will follow the hierarchy of preferred approaches shown below in setting permitting standards:

i. Set performance standards based on ambient environmental goals.

ii. Set performance standards based on technological achievability.

iii. Set technology- or management-specific standards. The ideal approach is where EPA sets performance standards based on actual environmental needs and projected impacts. EPA and other environmental agencies should follow this approach wherever possible and appropriate. It may be appropriate to combine the above approaches in an overall permitting system (e.g. establish a base level of performance and only require higher levels of performance where

environmental conditions are not being achieved). This later approach is currently prescribed by statute in many of the Agency's permitting programs.

In cases where EPA is not able to establish permit conditions based on environmental needs, e.g., due to costs and complexities involved with obtaining useful ambient data, or due to methodological difficulties (there are significant difficulties with implementing ambient standard schemes, including contentious scientific issues), the second-best approach is for performance standards to be based on what is technologically achievable. For example, based on EPA's knowledge of the removal efficiency of a particular water pollution control device, the Water program may set a numerical standard that facilities will have to meet in order to be in compliance with statutorily established control standards. While the permitting program will make information available about what technologies are capable of achieving that standard, it will allow the facilities to make their own determination of what technologies to use to meet the numerical standard. In some cases, facilities may substitute a technology or procedure at earlier stages of its process, rather than at the end of the pipe or smokestack, so as to more efficiently prevent pollution and save having to deal with its consequences.

There will be instances in which technology- or management-specific standards are warranted. For example, the underground injection control (UIC) program has a non-degradation policy backed up by engineering requirements that are supported by industry as well as by the permitting agency. In this program, the cost of ambient monitoring to ensure compliance would be excessive compared to establishing technical requirements.

B. Increasing facilities' Operational Flexibility

In addition to allowing permittees the flexibility to determine the technical means by which they meet EPA standards, there are several other ways to increase permittees' operating flexibility. Permitting agencies should consider these alternatives and incorporate them into their permitting processes as appropriate. Any alternatives that provide increased flexibility to the regulated community need to ensure that the requirements are enforceable.

First, permitting agencies' review of permits should be more performance-based. This would involve reducing review steps to those needed to reasonably demonstrate that the permittee will meet performance standards. Upfront technical (engineering) reviews, therefore, would be reduced or even eliminated where possible and appropriate. In general, where technologies are already proven or verified, there would be less need to perform technical review as part of the permitting process. EPA will give state, tribal and local governments the flexibility to reduce such reviews. EPA Program offices will evaluate existing regulations, policies and priorities that limit this flexibility and make appropriate revisions where authorized by statute. In addition, EPA will evaluate whether to shift grants funding from this stage of the permitting process to other more productive stages (such as compliance assistance and enforcement). This flexibility in use of grants is consistent with the Performance Partnership Grant program proposed in the FY96 EPA budget.

As an example, the lengthy and detailed technical reviews often conducted under the RCRA program may be less necessary for many standard container and tank storage operations. The PIT is working on a project with California and Texas to develop a general (non-individual) permit for this class of facilities, thus substantially streamlining the RCRA permitting program.

As noted in Section II, permitting agencies should also be given the leeway to reduce reporting and compliance monitoring requirements which are deemed to be unnecessary or duplicative.

Second, permitting agencies will be allowed to reduce the number of times permits need to be formally modified. Currently, lengthy permit modification processes discourage facilities from making needed process changes—including changes which could *reduce* emissions. Generally, permit modifications should be required only where process changes will increase pollution, or are needed to ensure proper operation or monitoring of a facility (this is likely to require regulatory revisions in some permit programs). Permitting agencies should be able to tailor their permit modification requirements by facility; facilities with good compliance records may be made subject to less prescriptive requirements. Each EPA permitting program shall review their modification requirements and make appropriate revisions to only require permit modifications where needed to protect human health and the environment.

As discussed in Section I–D above, permitted facilities should be encouraged to establish mechanisms for conducting regular dialogue with the public, such as community advisory committees. Major changes in plant operations may well be appropriate topics for dialogue regardless of whether a permit modification is required.

Third, permitting agencies should use the permitting process to encourage municipal and industrial facilities to practice pollution prevention. One of the primary purposes of making permitting performance-based rather than technology-based is to encourage and allow facilities to pursue innovative technological approaches to preventing pollution at the source. However, additional incentives and technical assistance are needed. In addition to pollution prevention technologies, the permitting system should encourage the use of more cost effective innovative technologies of any type, where practicable and consistent with legal requirements.

In many cases, encouraging pollution prevention and innovative technologies will require facility-specific actions, e.g., drafting a flexible permit that allows the permittee discretion to do what is needed to prevent pollution. This is the approach of a major EPA initiative, Project XL, under which facilities are exempted from certain regulatory requirements if they can demonstrate that they will achieve better environmental results through other means. In addition, the PIT is working on a project with the state of New Jersey, under EPA's Environmental Technology Initiative (ETI), to develop and implement a protocol to encourage the utilization of innovative technologies and pollution prevention.

ETI is also sponsoring more than two dozen other projects, programs and demonstrations in order to remove barriers to technology innovation in the permitting process, through facility-specific actions as well as more general regulatory, administrative and procedural changes. The Office of Policy, Planning and Evaluation has established a program to coordinate these ETI permitting projects and to provide information and assistance to other EPA offices, state, tribal, and local permitting agencies, and outside groups.

Turning to the additional incentives needed for encouraging pollution prevention the Pollution Prevention Incentives Task Force recommends, among other things: (1) increasing the use of facility-wide permitting, and (2) inserting language in general permits stating that pollution prevention is the preferred means of reaching compliance. Permitting agencies, at their discretion, may decide to use

similar incentives to encourage recycling or other beneficial management methods as well as pollution prevention.

EPA's Multi-Media Pollution Prevention (M2P2) Permit Project is currently working with several states on multimedia permitting. This should become the long-term direction of EPA's permitting programs; however, the transition from single-medium to multi-media permitting will take time and careful planning. EPA's evaluation under the M2P2 Project will be used to plan that transition.

C. Public Performance-Based Compliance Assurance and Enforcement

Regardless of the level of flexibility provided to permittees, there will always be a need for environmental agencies to monitor, assure and enforce compliance with permits. In fact, where upfront technical reviews are reduced or eliminated, these functions become even more important. Whereas the existing permitting system is in some way geared to hold all permittees to requirements based on the worst-case scenario, the proposed system would gear requirements to actual environmental performance. A tiered approach to compliance assurance, is one possible approach, under which less significant violators are provided technical assistance, while more significant violators become subject to penalties that should be harsh enough to deter activities that may threaten human health or the environment.

In addition, information about permittee compliance performance should become available to the public in clear, user-friendly databases and publications. It is not enough for an industrial or municipal facility to perform to the satisfaction of the permitting agency; the surrounding community has the right to know how well a facility is complying with its permits and use this information for itself. The concept behind this approach is to employ the power of public disclosure, so that a permittee would be deterred from violating permits by the public relations implications of poor compliance, or conversely be encouraged to maintain a high level of compliance by the public relations benefit of being in compliance.

The Office of Enforcement and Compliance Assurance (OECA), in consultation with appropriate stakeholder, will investigate and recommend ways to publicize, in an easy to understand format, facilities' compliance records. Some possibilities are an annual report (developed by the permitting authority) or requiring compliance reporting as part of a facility's permit. This compliance reporting could be based on a third-party audit, conducted by an impartial auditor, or a self-audit, possibly used at facilities with excellent compliance histories. The developed approach would probably have to be piloted in particular media programs, Regions or states before it is ready to be applied to all permitting programs individually and on a multimedia basis. It will also require study by OECA to ensure that this system is successfully designed to be legally defensible, fair, efficient and enforceable.

The criteria behind the compliance reporting should take several factors into account. First, there should be a clear distinction between paperwork violations of little or no direct consequence to the environment and permit violations with the actual potential to damage the environment or human health. It is recognized that certain paperwork requirements are critical to determining permit compliance. Furthermore, continued violation of paperwork requirements should result in enforcement action. Second, there could be separate ranking systems for small and large facilities, since they face different challenges when it comes to permit compliance. (With small facilities, the greatest challenge can be having the time and resources to understand and afford to comply with permit requirements. With larger facilities, the top challenge may be achieving compliance given different process lines, smokestacks, discharge pipes, etc.). Regardless of the final criteria used, they should be clear enough that there is no dispute as to whether or not a facility is in compliance.

Compliance assurance and enforcement activities should also take into consideration facilities' compliance records. This could help EPA and state, tribal and local permitting agencies to better target inspections, enforcement actions and penalties based on the severity of the violations. For smaller facilities with labelling or paperwork violations, EPA may target technical assistance at them (e.g., in cooperation with universities or other programs which provide such assistance) so as to improve their understanding of permit requirements and how to comply with them.

On the other hand, facilities whose non-compliance has the potential to threaten human health and the environment more significantly, should be much higher priorities for reporting, monitoring and attention. In the most severe cases, EPA or the permitting authority should reserve the option of halting a plant's operations until it complies with essential permit conditions. This targeted enforcement approach should make it possible to respond to the worst threats in a more immediate fashion.

IV. Agency Performance

No reform can ever permanently solve every problem with a particular system, because problems and public perceptions of them are constantly evolving. Therefore EPA, state, tribal and local permitting programs should institute systems of continuous evaluation and improvement of their own performance.

As illustrated in Figure II, this system would involve several steps:

(1) Identify performance standards for the permit program: the PIT's Performance Measures Task Force has developed draft standards by which permit program performance could be measured, including timeliness of permit reviews, permit backlogs and customer satisfaction.

(2) Determine how these standards would be measured: e.g., design surveys to measure customer satisfaction. As part of EPA's Customer Service efforts, surveys have been drafted for citizens involved in permitting decisions, permit applicants and delegated/authorized permitting agencies. Customer service standards have also been drafted based on these surveys. Surveying will begin in Federal Fiscal Year 1996. This step needs to be carefully designed to avoid burdening agencies with tedious ''bean-counting'' exercises. Streamlined ways of recording performance, including user-friendly electronic means, are encouraged.

(3) Compile performance data: e.g., conduct surveys, measure performance rates, etc.

(4) Report to public on permit program performance: compile results into a regular (e.g., yearly) report on performance which is clearly understandable and easily accessible, in print as well as on the Internet. Establish mechanisms to receive public feedback, via Internet, phone and mail. Permit programs may also decide to hold public meetings or focus groups to obtain more feedback, as appropriate.

(5) Review permit program standards, processes and approaches based on evaluation results and public feedback: permit programs should conduct periodic program evaluations based on the input received from this process. They should determine what changes to implement in their programs to respond to any shortcomings in performance.

Performance standards will also need to be periodically revised to respond fully to program needs.

(6) Revise permitting program processes and approaches: implement the changes that have been identified and return to step one of the continuous performance improvement system.

The performance of EPA and other permitting agencies, like the performance of permittees and the actual condition of the environment, needs to be publicly reported in clear, understandable terms. By bringing these types of performance into the light, public performance-based permitting will focus attention on the results of environmental permitting systems, and use those results to continually make these systems more responsive and environmentally protective.

ADMINISTRATIVE STREAMLINING—TASK FORCE RECOMMENDATIONS

Goal for Administrative Streamlining

The goal of the Administrative Streamlining Task Force was to improve the permit process by analyzing successful permit programs across the country and recommend permitting process changes (guidance, policy, regulations, procedures) designed to apply these successes more broadly.

Recommendations

1. Create a Predictable, User-Friendly Federal Permit Process

a. Information and Process

Currently, EPA permitting programs have different processes that follow different timeframes (See Attachment 1). The lack of coordination among these programs, and the lack of predictability created by this situation, can unnecessarily complicate the permitting process for permittees, state, tribal and local permitting authorities, and the public. In addition, EPA's oversight of delegated or authorized permitting programs varies by Region and media program.

Therefore, EPA should to the extent consistent with its various statutory authorities develop one unified, standard timeline model applicable to all of its permitting programs (it may be necessary to have one model for new permit applications and permit modifications and another for facilities that are required to upgrade to meet new requirements). It may also be necessary to have different timelines based on the type of permit (e.g. major or minor). This model timeline is intended to be used as a management tool for permitting agencies to set realistic and desirable time goals; if goals are not being met, permitting agencies should review their processes to identify and eliminate inefficiencies and unnecessary or unproductive procedures.

In the short term, one uniform model should be approved by EPA as non-binding guidance for state, tribal and local permitting authorities. Where allowed by statute or regulation, EPA permitting programs should provide sufficient flexibility to allow authorized permitting authorities to adopt this timeline in lieu of specific program timeframes.

Appendix 2 contains a proposed uniform timeline model. Under this model, the timeline would be subject to extension if the applicant consents to negotiate permit terms, if the applicant must submit further information, or if the permitting agency determines that the project is unusually complicated. The process should include a mechanism that clearly identifies the reason for any time extension and whether the applicant is responsible for any actions that would re-start the clock on the timeline. The applicant's failure to submit needed information would constitute a basis for denying the application. The timeline could include options for enforcing the time limits and ''calling the question'' on the permit action, as determined by each permitting jurisdiction.

Several options for ''calling the question'' on a permit application were considered by the Task Force. One option would include a refund of permit fees for failure to meet the timelines. A few states have implemented this approach. Another option would be a judicial cause of action or other administrative remedy to compel agency action on the permit, if the controlling statute made meeting the deadline a non-discretionary duty. A third option would be to allow a permit to go into effect automatically if the agency does not meet the deadline. This option is inconsistent with current law and would be contrary to the PIT's recommendations to enhance public participation and is therefore not endorsed by the PIT. In addition, this option may also foreclose the ability of the permitting authority to adequately evaluate appropriate considerations under Title VI of the 1964 Civil Rights Act, such as, any disproportionate impact of the permit action on minority communities.

Permits that are issued by the Regions or by state, tribal or local permitting authorities that are authorized pursuant to federal law would have legal impediments to some of the above options. Most importantly, if the last option caused the elimination of required public participation the resulting permit would not comply with federal law.

The proposed timeline includes a notice to the public of either the complete application, the proposed draft permit, or both, depending on program needs and statutory constraints.

Implementation (short term): Each EPA Program office should release a uniform model timeline (by permit type—major/minor) to its authorized authorities as guidance, and establish, as policy, that Regions and state, tribal and local permitting authorities, to the extent allowed by statute and regulations, will be allowed to follow this timeline in lieu of specific EPA permitting program timeframes that may otherwise conflict with it.

Implementation (long term): A high-level cross-office team should be established in FY96 to reach consensus on what changes should be made to EPA statutes, regulations, policies, guidances and processes so as to bring all major EPA permit programs under a single uniform timeline and oversight approach. This team should also define the resource burden of making these revisions along with the potential savings from reducing EPA oversight of delegated or authorized agency issued permits. The PIT has already identified some of the statutory and regulatory barriers to a uniform timeline. The proposed team would, with stakeholder input, agree on the specific changes to be made and work with Program offices to ensure that these changes are implemented or proposed for statutory change.

b. Single Point of Contact for All Media Permits

In addition to basic level, point of entry offices, each permitting agency should assign senior permitting personnel to projects in which a facility receives multiple permits. This can help ensure cross-program permit coordination and provide each permittee with one senior staff contact to coordinate the resolution of any cross-cutting issues. In cases where state/tribal/local permits and federal permits are being issued to the same facility, permit coordination is also needed between the permitting agencies.

Example: EPA Region 6 multi-media permit teams.

Implementation: We recommend that a PIT workgroup draft policy and operational guidance, to be issued by EPA's Administrator, for Regional Administrators to implement a single

point of contact approach during FY 1996.

2. Encourage and Implement Flexible Permitting Projects

EPA and state, tribal and local permitting authorities should create opportunities for facilities to negotiate alternative permit conditions that maximize operational flexibility and encourage pollution prevention while maintaining or increasing levels of environmental protection. Each permitting agency should identify those situations where a modification can occur without review. Presently, initiatives such as Project XL, the Common Sense Initiative (CSI), the Environmental Technology Initiative (ETI) and the Clean Air Act Title V permit program are piloting approaches and mechanisms to promote greater flexibility in permits.

Examples of flexible permits:

• Intel Corporation, U.S. EPA, the Oregon Department of Environmental Quality, and the Pacific Northwest Pollution Prevention Research Center developed a flexible Title V operating permit with the goal of accommodating shifts in emissions within the facility and encouraging pollution prevention, while preserving the enforceability of the Clean Air Act's requirements. Under ETI, EPA Regions 1, 9 and 10 are working with the Office of Air and Radiation; the Office of Prevention, Pesticides and Toxics; and the Office of Policy, Planning and Evaluation to expand the Intel flexible permitting experience to several other states and industries. This national expansion of the Intel experience will provide EPA and the States with valuable information and will help ensure the development of enforceable Title V regulations that allow for permit flexibility and the incorporation of pollution prevention and innovative control technologies.

• EPA and Minnesota Pollution Control Agency worked with 3M corporation to develop a flexible permit which, while ensuring all necessary environmental protection, allows the source to make physical and operational changes without triggering major new source review requirements under the Clean Air Act.

Implementation: EPA should, through Regional Offices, serve as a clearinghouse for good examples of flexible permits and serve as a resource to state, local and tribal governments and the public in implementing these approaches. This proposal should be implemented through the electronic clearinghouse recommended in 4d below, as well as through the Regional Permit Process Assistance program recommended in 5 below.

3. Tier Permitting Programs in Proportion to Environmental Significance

EPA should establish a policy and guidance to encourage state, tribal and local permitting authorities to tier their permit programs according to the environmental significance of facilities' polluting activities. Such a policy should allow agencies to reduce monitoring or other reporting requirements for less significant activities so agencies can focus on the actions with the greatest potential for environmental impact.

Suggested ways to do this include: increasing thresholds for small emissions; exploring use of impartial third-party certification systems; exempting certain activities; requiring less frequent/consolidated reporting; expediting the review for low tier permits; and providing incentives for good compliance records and for use of pollution prevention approaches. Some of these approaches would require regulatory and possibly statutory changes in order to be implemented.

Examples: A number of states are moving towards tiered permits, to reduce permit process requirements in accordance with the location of the project, environmental significance of the impact imposed by the project, etc. Examples include California Tiered Permitting for hazardous wastes, Minnesota's Air and RCRA Programs, and the Massachusetts 401 Certification Program.

Implementation: As an FY96 project, a PIT workgroup should conduct an analysis of current approaches to tiered permitting, and then, based on this analysis, draft EPA policy and guidance promoting such approaches where appropriate. This analysis should also focus on projects such as Project XL, to determine where principles applied to individual facilities (e.g., pollution prevention incentives) can and should be applied to whole classes of facilities.

4. Establish Computer Systems

a. Integrated Facility Data Bases with Geographic Information System (GIS) Interface

Permitting authorities should combine cross-media information for each facility into a single database which provides instant access and search capability. EPA has initiated this task at the national level through the efforts of the Key Identifiers Workgroup.

Example: Massachusetts DEP's Environmental Protection Integrated Computer System (EPICS) system takes information supplied by 12 separate MADEP divisions, such as air emissions, hazardous waste and water supply and combines it into a single database. This gives MADEP employees instant access to all the agency's information and allows them to search for data on a facility by entering its name and location. This and a two-year cross-training program have allowed inspectors to do multi-media inspections. EPICS is currently developing an interface with GIS to help site new businesses and to assess cumulative threats to resources for targeted compliance/enforcement.

b. Permit Software Systems

EPA should collect and make available state, tribal, local and regionally developed software for a menu-driven system to train permit-writers and assist them in drafting permits. The system should contain and cross-reference all appropriate regulations and procedures, and provide a mechanism for tracking.

Examples: Maryland/Region 3 software program for NPDES permit writing and tracking. Also, the Indiana Department of Environmental Management has begun a project to develop a menu-driven, expert system to help permit writers in drafting permits. This project was started in an effort to provide training to new permit writers in the state. The expert system takes permit writers through the process of writing a permit, cross-references all appropriate state regulations and internal procedures, and results in a draft permit. This system could also be made available to permittees and the public.

c. Electronic Permitting and Reporting

EPA should facilitate permitting authority efforts to provide permit application forms on disk or by dial-in, issue permits electronically (while providing for public notice, access and opportunity to comment), develop permit tracking capability, and establish electronic facility-based compliance reporting. Model permits (like the RCRA model permit) in electronic format may be provided to applicants to fill-out as a supplemental part of their permit application if they choose to do so. This can greatly reduce the time required for a permit writer to transform permit application proposals into permit conditions. The permit writer can also easily verify that the permit conditions proposed by the applicant meet all applicable requirements. The use of electronic exchanges in permitting will not replace the need to continue to

provide appropriate permitting information through non-electronic means.

d. Electronic Database/Clearinghouse

EPA should establish, provide access to and maintain an electronic database/clearinghouse which contains relevant information necessary for permit writers in all media, including: pollution prevention, toxics use reduction, pollution allocation/Total Maximum Daily Load (TMDL) models, site specific protocols, etc.

Implementation: Recommendations 4a-c above should be referred to EPA's Office of Information Resource Management to identify existing capabilities, develop resource needs and schedules to adopt across media Program offices. Recommendation 4d should be referred to Research Triangle Park's Internet Group to identify existing capabilities, develop resource needs and a schedule to allow adoption across media Program offices.

5. Regional Permit Process Assistance

Under the National Environmental Performance Partnership System agreed to between EPA and the states on May 17, 1995, EPA will be reducing direct oversight of authorized state programs. The Regions are in an excellent position to help the states improve their permitting processes by keeping abreast of the latest changes that are being implemented, and sharing that information with the states. Working together, a Region and state would identify areas in need of improvement in a permitting process and evaluate existing approaches that have been utilized to help address the identified area.

Implementation: As an FY96 PIT pilot project, a Region and a state (possibly Texas) should develop an approach whereby the Region would assist the state in evaluating a permitting process. The purpose of this evaluation would be for the Region to help identify improvements that could be implemented. The Region would make use of national clearinghouses and data bases (see recommendation 4d) to help identify approaches that could be of assistance to the state. The Region could also provide any needed training to the state. The state would make the final decision on implementing any improvements.

The Region (with input from the state) would prepare a report on the lessons learned from this pilot and, working with a PIT workgroup, propose an approach that other Regions could utilize in providing assistance to states and tribes in their respective region.

Attachments:

1. A table of current permit program timetables.

2. A proposed uniform timeline for all major and minor federal permits (see Recommendation 1.a., above).

ATTACHMENT 1.—FEDERAL PERMIT PROGRAMS, CURRENT TIMETABLES

Statute	Public notice requirement	Public hearing requirement	Permit duration
RCRA [1]	Notice of draft permit in newspaper and radio. 45 day comment period.	30 day public notice. Required if written opposition to draft permit.	10 years, review every 5 years for land disposal facilities. May be reviewed/modified at any time.
Prevention of Significant air quality Deterioration (PSD).	Notice of draft permit in newspaper. 30 day comment period.	30 day notice. Silent on threshold	No expiration date. New permit required to modify.
Clean Air Act Title V	Notice of draft permit in newspaper. 30 day comment period.	30 day notice. Silent on threshold	Up to 5 years. 3 types of modifications follow new permit process.
NPDES	Notice of draft permit in newspaper. 30 day comment period.	30 day notice. Silent on threshold	5 years.
UIC	Notice of draft permit in newspaper. 30 day comment period.	30 day notice. Silent on threshold	Classes I & V: Up to 10 years. Classes II & III: Up to operating life.

[1] These requirements do not include the changes for enhancing public participation included in RCRA Expanded Public Participation Rule.

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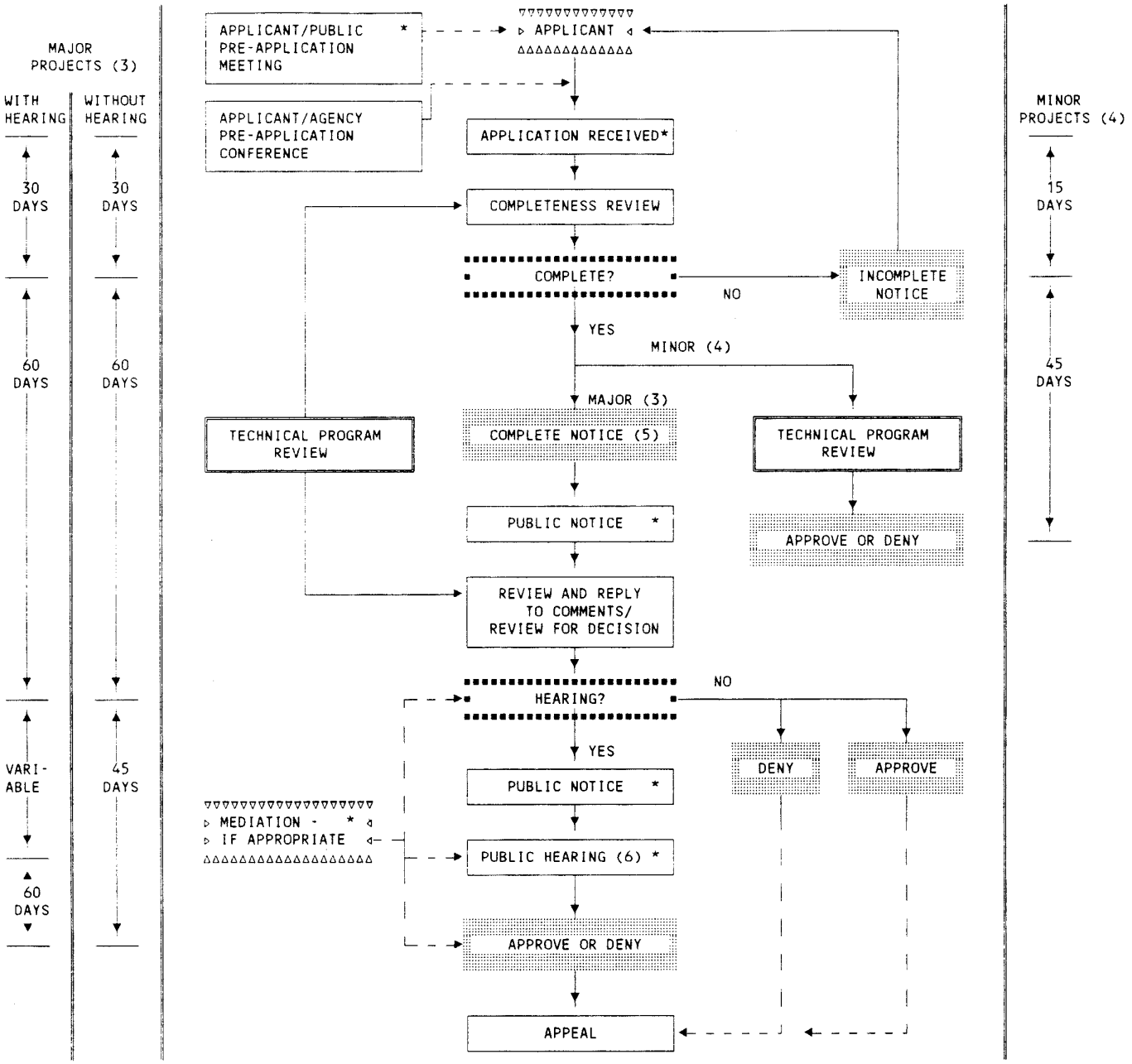
ATTACHMENT 2: AUTHORIZED & DELEGATED PERMIT PROGRAMS PROPOSED UNIFORM PERMITTING PROCESS (1,2)



Notes

* Opportunities or requirement for public participation.

(1) Time frames can be waived with mutual consent, or if applicant is unresponsive.

(2) Procedure to apply to all programs except siting.

(3) Major projects receive full public participation opportunity. They are the projects most likely to have significant environmental impact.

(4) Minor projects receive internal review only. They represent minimal or no environmental threat.

(5) ''Complete'' notice can be published when application is determined to be complete, or when draft permit has been agreed on, or at both milestones.

(6) Public hearings may be evidentiary or administrative, at states' option.

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ALTERNATIVES TO INDIVIDUAL PERMITS—TASK FORCE RECOMMENDATIONS

A. Background/Approach

The Permits Improvement Team is exploring alternatives to individual permits in order to deliver government services more efficiently, target EPA resources at environmental priorities, and encourage pollution prevention. EPA's National Performance Review included the goal ''Target Permit Priorities'', with the following objectives:

- Issue individual permits only where there is a high degree of environmental concern and where it is necessary to apply tailored or site-specific requirements.
- Use alternatives where possible, such as compliance with self-implementing regulations (e.g., permit-by-rule) and general or class permits.

This report refers to six different types of permitting, defined below:

Individual permitting refers to authorization granted to a person through an adjudicatory process on a site-specific basis. Typically, the permittee initiates the individual permitting process through submission of an application. The permitting agency then develops a proposed permit (which may or may not be developed in coordination with the permit applicant) and publishes notice of the proposed permit for public comment. After consideration of public comments, the permitting agency will issue a final decision on the permit application. In some instances, permitting agencies provide an opportunity for administrative appeal of a final permit before it becomes effective.

General permitting refers to a rulemaking-type process where requirements are developed based on a prototype facility. The permitting agency develops a general permit applicable to facilities or activities of substantially similar nature. General permit authorization is granted after a person registers with the permitting authority its intention to comply with the terms of the general permit. The general permit rulemaking process may be initiated by the permitting agency or by petition to that agency. Depending on programmatic needs and legal requirements, a hearing may be required on whether the general permit applies to a particular facility (or activity). Typically, general permits are issued for environmental activities of ''medium to low'' concern where there is little variability from the prototype facility or activity considered in development of the general permit. Under the Clean Water Act, general permits are widely used, particularly for storm water discharges. Public involvement occurs at time of development of the general permit.

Hybrid permitting refers to a combination of general permitting and individual permitting. Though the permittee is subject to a single permit, the permit terms with which the permittee must comply are developed in part through rulemaking (general permit) and in part through adjudicatory processes to determine site-specific requirements (or to comply with site-specific notice or applicability requirements). Hybrid permitting is not currently used by EPA, so there is no established procedure, but such a process could be established through modification of the general permitting process. Hybrid permitting may be more appropriate than general permitting where there is greater variability from the prototype, or where there is a statutory requirement for site-specific hearings.

Permitting-by-rule (PBR) refers to authorization that does not require subsequent action either by the permit applicant or the permitting authority. For certain RCRA requirements, EPA has issued permits-by-rule when compliance with a permit under one statute is ''deemed'' to be permitted under RCRA. Alternatively, a general permit that does not require registration may be considered to be a permit-by-rule.

De minimis exemptions to permitting refers to the regulatory exclusion of an activity that might otherwise fall within the scope of activity regulated by a statute. Application of the *de minimis* exemption theory is subject to some legal restrictions.

Conditional exemptions refer to activities which are not subject to permitting if the conditions of the exemption are met. Conditional exemptions would be used where it is important to establish some ''non-permit'' substantive standards; e.g., a standard of performance or management practice. Conditional exemptions may represent an enforceable means to establish that a facility/site/source falls below some ''applicability threshold'' for a given permit program (such as a *de minimis* pollution threshold). Conditionally exempt activity is not subject to permitting, but is subject to some enforceable requirement. The conditional exemption theory has not yet been tested in the courts.

B. Methodology for Choosing Recommendations

This Task Force's recommendations were based upon the following criteria:

- *Issue permits* only where there is a real or potential adverse environmental impact and the regulatory agency needs to be involved (add value) in developing proper controls.
- *Issue individual permits* only where there is a potential significant environmental impact or high degree of variability in regulatory requirements at individual facilities.
- *Involve the public* in the development and implementation of any alternatives to individual permits.
- *Ensure adequate compliance and enforcement* activities where alternatives to individual permits are developed.

C. Recommendations

These recommendations need to be implemented by the applicable EPA Headquarters permitting program. As part of that implementation, each Program office needs to review their legal authority for utilizing alternatives to individual permits. If the statutory authority exists but current regulations restrict the use of alternative approaches, the Program office will propose appropriate revisions.

General Recommendations

1. Each Program office should formally consider the appropriateness of using alternative permit approaches. Consider the degree of environmental risk, level of public interest, site variability in application of requirements and duplication of state, tribal, and local permits in establishing permitting approach.

2. In administering EPA-issued permits, each Regional office should consider the performance of state, tribal and local permit programs that may regulate the same or similar activities. Regional offices may appropriately provide a less rigorous level of review in those jurisdictions where the state, tribal or local permitting authority provides equivalent protection. In some cases, where a facility may operate lawfully without a federal permit, it maybe appropriate for the Regional office to place lower priority on issuing federal permits in such jurisdictions. Where the facility is required to have a federal permit, EPA Program offices should investigate the development of general permits that reference the state, tribal, or local permits.

This recommendation does not solve the underlying problem of authorizing state, tribal and local permitting

programs that provide a substantially equivalent program but not identical to EPA's approach. Each Program office should revise their regulations to streamline the authorization process and provide for greater flexibility where allowed by statute. If a statutory barrier exists, the Program office should seek revisions to the statute to provide clear direction on when authorization can occur.

3. Each EPA Program office should develop and maintain a clearinghouse of permit alternatives being developed and used in federal and state/tribal/local programs throughout the country. The Program offices should consult with their state, tribal and local counterparts to determine the most appropriate information to provide, given available resources. State, tribal and local permitting programs are encouraged to submit copies of any alternative permit approaches in electronic form for ready use by other permitting authorities interested in pursuing similar approaches.

Program Specific Recommendations

1. Stormwater—National Pollutant Discharge Elimination System (NPDES)

a. The Task Force agrees with the Office of Water's ongoing permit reform efforts for Phase I and Phase II, conducted under a Federal Advisory Committee Act (FACA) charter, and recommends they be continued.

b. The Task Force agrees with the further development of general permits as part of Office of Wastewater Management's (OWM) projected permit improvements in the NPDES program in the final 1992 Non-Construction Industrial permit and the proposed Multi-Sector stormwater general permit and recommends they be continued. Specifically;

- The development of general permit language that emphasizes pollution prevention (P2) and Best Management Practices (BMP)in the Non-Construction Industrial permit and the Multi-Sector permit.
- The establishment of appropriate monitoring requirements, based on industry type, water quality, or capability to implement BMP.

c. The Task Force recommends the continued use of the clearinghouse for general permits.

d. Where non-approved states, tribes, or localities are issuing substantially similar permits, EPA Regions should defer to those permitting authorities by prioritizing permitting actions to focus on non-approved permitting authorities *without* substantially similar programs.

2. NPDES—Process Wastewater

a. Because of the need to control specific dischargers, individual permits should be maintained for water quality limited areas, where Total Maximum Daily Loads (TMDL's) are necessary or wherever specific conditions to be addressed in a permit are not amenable to a general permit.

b. Permit duration should be increased from 5 to 10 years or the life of the facility. Under this approach, there should be a provision to allow permits to be re-opened if there are facility, regulatory, or water quality changes. This recommendation requires a statutory change. This increase would be an incentive for states to move toward the watershed protection approach.

c. OWM should develop and expand the use of general permits in non-water quality limited areas and non-TMDL areas through policy directives, development of general permit boilerplates and establishment of a national clearinghouse of general permits.

d. A permit-by-rule (PBR) should be established for de minimis discharges that establishes threshold conditions below which no reporting would be required. They could be based on industry-type, percentage of loading, etc. The rationale for the established PBR for Metal Products should be used to develop de minimis PBR's for other discharge categories.

Recommend PIT FY'96 Pilot Project with the State of Washington, Region X and OW to develop PBR for de minimis discharges.

e. Overall monitoring requirements should be decreased, but include ambient as well as end-of-pipe monitoring. Ambient monitoring would be used primarily to set permit limits where national technology based standards and state water quality based standards have not achieved environmental goals.

The PIT recommends a Pilot Project be conducted by OW, with a Region and State, to determine achievement of program goals.

3. Toxic Substances Control Act (TSCA)

The Task Force's initial recommendations included the consolidation of PCB disposal requirements into the RCRA requirements. However, the current position of the Office of Solid Waste (OSW)/Office of Pollution Prevention and Toxics (OPPT) workgroup evaluating this issue, for a variety of reasons, is to leave the two programs separate but to improve communications to make them more compatible. This Task Force defers to the workgroup on this issue.

The workgroup is identifying options that can be readily implemented to improve the disposal of PCB's, while considering costs to industry, states (unfunded mandates), and EPA. Several potential goals have been identified to help direct the workgroup's efforts:

1. State primacy for the PCB disposal program (one stop shopping) (may require statutory change);
2. Consolidation of hazardous waste requirements (avoid program duplication); and
3. Utilization of EPA grant money for state actions (PCB and hazardous wastes).

The Task Force recommends that the PCB combustion authorization requirements be incorporated into the Air permit program if legally permissible. Other portions of the TSCA program would remain in OPPT. This recommendation is consistent with the recommendation below concerning the Resource Conservation and Recovery Act (RCRA) combustion program. This recommendation avoids the problems associated with incorporating the PCB disposal program into RCRA, but would place all permitted air emissions under one program.

The PIT recommends an OPPT and Office of Air and Radiation (OAR) workgroup be formed to develop appropriate procedures.

4. Safe Drinking Water Act—Underground Injection Control (UIC) Program

a. Shallow injection wells (Class V wells): Continue use of authorization by rule, which has been granted to all Class V wells, providing that they comply with certain minimal requirements (e.g., well inventory) unless the well may endanger underground sources of drinking water.

b. Injection of fluids related to oil and gas production (Class II wells): Where appropriate, continue use of area permits; promote use of non-individual permits by authorized permitting authorities.

c. Individual permitting should continue for Class I wells (deep wells for industrial, municipal and hazardous waste).

5. RCRA Permit Program (See Attachment for More Detail)

The PIT specifically notes that there are regulatory or statutory barriers to some of the approaches listed below. The Agency's ability to implement each of these options under the current law would need to be investigated further as

these options are developed in more detail.

RCRA Base Program

a. Maintain individual permits for facilities requiring operating and post-closure land disposal permits.

b. OSW should establish a general permit boilerplate and promote the use of general permits for non-commercial storage or treatment facilities, including, for example, laboratories. The general permit conditions may need to be supplemented, in some cases, with site-specific conditions identified by the permitting authority or through local public participation. In this situation the permit would be a hybrid permit.

PIT FY'96 project to pilot the use of general permits in the states of California and Texas with Regions VI and IX and OSW.

c. Extend the generator storage time frames from 90 to 270 days for laboratories as part of regulatory re-invention.

d. For hazardous waste combustion facilities, Regional offices should incorporate RCRA requirements into the Air permit program, where both apply; a facility's Air permit would address both Air and RCRA combustion and emission requirements (this is one alternative provided for in EPA's proposed Hazardous Waste Combustion Regulation, Subpart O). Other RCRA requirements (e.g. storage and non-thermal treatment, corrective action) would be addressed through either an individual, general or hybrid permit. This recommendation should be implemented after the proper regulatory authorities are in place. Revised RCRA and CAA regulations are expected to be proposed in March 1996.

RCRA Corrective Action

a. Allow a facility to perform corrective action through a state/EPA order cross-referenced in the permit, or through an individual, general or hybrid permit.

b. Prioritize the issuance of corrective action permits and orders by focusing on state programs that are not authorized and that do not have substantially similar cleanup programs. States with substantially similar programs should be a lower priority. The de-coupling of corrective action from RCRA permitting is being considered as part of the Subpart S regulations (see Advanced Notice of Rule Making—expected to be issued 4/96) and Post-Closure rule (Subpart C) proposal. Under this approach a Region would be relying upon another agency to serve as lead in this situation.

c. EPA should focus the majority of its corrective action resources on states without substantially similar cleanup programs. To achieve maximum overall environmental benefit, EPA should also explore allowing EPA RCRA resources to be shifted to support states in clean-up of higher state priority non-RCRA facilities. The legal authority to implement this recommendation needs to be evaluated.

d. Subpart S needs to provide incentives for performing clean-ups by allowing conditional exemptions from permitting for:

—On-site storage of contaminated media and off-site storage and transfer of clean-up waste, especially from spill response activities,

—Non-RCRA facilities performing voluntary clean-ups.

e. Low-priority RCRA facilities should be allowed to conduct voluntary (early) corrective action through general or hybrid permits, memoranda of agreement between the facility and the permitting authority that achieve defined performance standards, or through amendments to the interim status regulations. There may be obstacles to using memoranda of agreements, since they would not provide legal protection to a facility that is required to obtain a federal permit.

f. Investigate third-party certification of general and hybrid permits for hazardous waste management that is generated through corrective action activities. (See Administrative Streamlining Recommendation #3, page 23, for broader recommendation concerning third-party certifications.)

PIT recommends review of MA initiative to utilize third party certification to determine if it is appropriate in RCRA.

g. Fast-track the Hazardous Waste Identification Rule (HWIR) and Definition of Solid Waste Rule, to limit regulation to wastes that are truly hazardous, allow general or hybrid permits to regulate recyclers and utilize the HWIR media rule concept of remediation management plans (RMP) for off-site storage and treatment of remedial waste.

6. Air—New Source Review (NSR) Permit Program

a. The Task Force agrees with the Office of Air Quality Planning and Standards (OAQPS) NSR reform efforts, particularly the following;

- Implementing plant-wide applicability limit (PAL) policy.
- Allowing states more flexibility to match the level of permitting effort to environmental significance. This recognizes that there may be facilities which do not require permits at all.
- Including special provisions to encourage the use of innovative technologies.
- Acknowledging and promoting pollution prevention activities.

If the NSR reforms do not receive stakeholder support, consider establishing a PIT workgroup to conduct an independent evaluation and develop recommendations.

b. Develop a more expansive definition of minor sources through the use of the following:

- Re-define the potential to emit to recognize the inherent operating limitations in defining this concept. The current definition is not realistic in addressing the highest environmental priorities.
- Develop and promote the use of general permits by preparing boilerplate language for applicable sources and establishing a national clearinghouse of general permits.

c. State, tribal and local permitting authorities should establish additional de minimis levels for selected minor sources under which no permit would be required, in conformance with existing regulations. This will provide that only true health and environmental risks require permits.

7. Air—Title V Permit Program

a. The Task Force supports the National White Paper and Supplemental Part 70 proposal, and recommends:

- Evaluating techniques to take inherent operating limitations into account in determining potential to emit.
- Investigating methods to simplify the renewal process to allow for automatic renewal upon recertification that no facility changes have occurred and no new requirements have come into effect since the initial permit issuance.

b. Develop and promote the use of general permits for sources with low actual emissions by preparing boilerplate language for applicable sources and establishing a national clearinghouse of general permits.

PIT recommends a FY'96 pilot project with the State of Iowa, Region VII and OAQPS to develop general title V permits (e.g. for paint booths). This project should be coordinated with the ongoing ETI Title V project.

c. Allow a self-implementation alternative for facilities with actual emissions of less than 50% of applicable standards.

- Implement flexible permits, through the use of plant-wide applicability (PAL) limits.

• Allow states more flexibility in deciding the most effective monitoring methods and controls.

d. Allow state, tribal and local permitting authorities to establish additional de minimis levels for selected minor sources under which no permit would be required. This will provide that only true health and environmental risks require permits. For example, in MA, emissions below 1 ton/year do not require a permit.

D. Attachment

A more complete discussion of the RCRA proposals follows.

Attachment—RCRA Alternative Permitting Recommendations

Task Force recommendations do not cover all aspects of RCRA permitting, but highlight areas both where continued use of individual permits seem most appropriate, as well as areas where alternatives may be particularly useful. Also, as is the case with some recommendations in other programs, there are regulatory or statutory barriers to some of the approaches listed below. The Agency's ability to implement each of these options under current law would need to be investigated further as these options are developed in greater detail.

RCRA Base Program

1. Continued Use of Individual Permits

The Task Force recommends continuing to use individual permits for facilities requiring operating and post-closure land disposal permits. Although some aspects of these facilities could be regulated by general permits or other alternatives to individual permits, the Task Force felt that the potential environmental impacts of these facilities particularly warranted regulatory attention and public comment on an individualized basis.

The Task Force also recognized that combustion facilities (incinerators, burners and industrial furnaces) warranted highly focused regulatory and public attention on an individual basis. However, efficiency could be obtained by having the impacts of these facilities reviewed in concert with air permitting. If so, the RCRA program could issue a general or hybrid permit to address any additional technical requirements not covered by the Clean Air Act permit process (e.g., corrective action), and could also address permit requirements for any ancillary units (e.g., storage units).

2. Ninety-Day Accumulation and Treatment for Generators

The Task Force also recommends providing guidance or otherwise clarifying the enforcement discretion available when a facility exceeds applicable time frames or violates any of the management conditions referenced in 40 C.F.R. § 262.34. The Task Force recommends that it be made clear that enforcement against such a facility may be handled as a violation of the specific requirements of § 262.34 (e.g., storage over 90 days, failure to mark containers, etc.) rather than as a failure to have a permit. Some prior agency statements have suggested that a facility that failed to mark a container would necessarily be subject to full permit requirements.[3]

3. Third Party Certifications

The Task force recommends consideration of the use of third party certifications both for corrective action and for hazardous waste management requirements. Where, for example, a regulatory agency might otherwise be inclined to require extensive regulatory review of a corrective action, unit design, contingency plan, or other RCRA-regulated activity in the context of an individual permit review, the agency might be able to shift that activity to a general or hybrid permit if the facility notification were accompanied by a third party certification that indicated comparable review has been conducted by an independent third party. There is a legal concern, however, presented by EPA's need to defend information and conclusions in the permitting decision that EPA itself did not develop.

RCRA Corrective Action

1. Corrective Action

Where a state with a well developed cleanup program is authorized for the base RCRA program, but has not yet become authorized for corrective action, the Task Force recommends that EPA consider issuing a ''rider'' general permit that would require treatment, storage or disposal (TSD) facilities receiving state RCRA permits to satisfy corrective action obligations by complying with the requirements of the state's cleanup program. For this approach to be legally defensible, EPA would need to explain the basis for finding that the state controls satisfy federal corrective action requirements. Another option would be for the federal permit to set a schedule of compliance for corrective action measures contingent on completion of the state cleanup in order to see whether further corrective action measures are necessary at that point. For this approach to be effective, EPA must be willing to defer to the State's overall site prioritization system. This may mean that there is less near-term cleanup at RCRA facilities, if there are higher priority non-RCRA facilities.[4]

Under this approach, EPA could then focus its resources and attention on corrective action in states without cleanup programs and on high priority RCRA facilities not otherwise being addressed by the states.

General or hybrid permits could include provisions that authorize low-priority TSD facilities not otherwise receiving regulatory attention to conduct early cleanups, subject to performance standards identified in the general permit (or through use of Memoranda of Agreement between the facility and permitting authority). Again, however, there may be legal barriers to these approaches under the current statute and regulations. An analysis of the possible alternatives to individual permits for corrective action and the legal barriers to those alternatives is ongoing within the PIT and its subgroup on general permits.

Another way to ensure that facilities receive federal permits would be for EPA to issue a permit that simply ''copies'' the state's permit, relying on the state's supporting record. EPA would not develop a record for the permit independently. In this approach, the facility would obtain a federal permit and would not be liable for operating without a permit. However, this approach would be viable only to the extent EPA feels comfortable that it will be able to defend against any permit challenges based on a record developed by a separate entity (*i.e.*, the state). The issue of deferral to the state, in general, is one that is still being examined by the PIT subgroup.

[3] *See, e.g.*, In the Matter of Humko Products, Docket No. V–W–84–R–014 (March 7, 1985) at p. 20 (facility storing waste over 90 days ''is subject to * * * the permit requirements of 40 CFR Part 270''), p. 26 n. 12; Permit Policy Compendium No. 9453.1989(05), Letter from Sylvia Lowrance to Stephen Axtell, April 21, 1989 (generator who fails to mark accumulation date ''has not met the pre-conditions for the exemption from permitting requirements and is an operator * * * subject to permit requirements'').

[4] EPA sometimes currently defers on a case-by-case basis to other cleanup programs in deciding how to address corrective action in a RCRA permit. In considering this recommendation, EPA might also consider whether its current practice sufficiently meets the goals of this recommendation, or whether there are alternative means of achieving a similar result through improvements on existing practice. For example, are there better ways of reflecting this deferral process in the permit than is currently the case.

2. Non-RCRA Cleanups

Many facilities that do not require RCRA permits have the potential to trigger RCRA permit requirements while conducting cleanups, whether voluntarily or under State direction. Many persons have noted that the possibility of subjecting a facility to full RCRA permitting, including fenceline-to-fenceline corrective action for cleanup activity is a disincentive to conducting focused cleanup and conversion of brownfields. EPA is currently developing approaches to many of these problems through the HWIR rulemakings. The Task Force recommends considering alternative approaches to permitting through the following scenarios which may go beyond the HWIR concepts in some applications:

- Off-site storage and transfer of cleanup waste, where the cleanup activity is being directed or supervised by EPA or a State regulatory agency ;
- On-site storage of contaminated media (includes voluntary cleanups as well as cleanups under regulatory supervision)(action would be subject to best management practices); and
- Activities at facilities not currently subject to RCRA conducting voluntary cleanup.

Of these various options, the last is most expansive, and goes beyond the more limited proposal for on-site storage of contaminated media. The second and third recommendations go beyond the HWIR approaches currently being considered in that they would apply to voluntary cleanups as well as cleanups under regulatory oversight.

ENHANCED PUBLIC PARTICIPATION TASK FORCE RECOMMENDATIONS

A. Background

An important ingredient for improving the permitting process is improving and expanding public involvement in the process. The Enhanced Public Participation Task Force was tasked with developing recommendations for providing opportunities for early and more meaningful public participation, including provisions for addressing environmental justice concerns.

Public participation has many aspects. It can be seen as involvement through participation in the permitting process—e.g., providing notice of upcoming events, or opportunities for meetings with businesses, communities, and regulating agencies. It can also be seen as involvement through access to quality information—e.g., businesses need quality information to identify opportunities to prevent pollution and save money, and communities need access to information to participate in decision-making in a meaningful and informed manner.

The Task Force looked into both areas, and developed five recommendations. The first three recommendations discussed in this report focus on short-term products (i.e., ones that might be developed in FY 1996) that are intended to fill an immediate need for information. These products may be used by permitting agencies, industry, and communities alike to (1) learn about potential ways to involve themselves or each other in the permitting process, and (2) find out what types of information are available, and how they can access it. These three recommendations were discussed with stakeholders and modified to incorporate their comments.

The remaining two recommendations were developed based on general public participation discussions that took place during the PIT's stakeholder meetings. These recommendations are good candidate projects for the continuing efforts of the PIT.

B. Task Force Recommendations

1. Develop An ''Easy Reference'' Guidance for Public Participation Activities

Description: The purpose of the guidance should be to serve as a valuable reference of public involvement activities. The guidance should not cover every possible type of activity. Rather, it should serve as a supplement to existing guidance developed by EPA Program offices, trade associations, or environmental groups. It could be used by businesses, communities, and permitting agencies in putting together public involvement strategies appropriate for particular situations. We recommend that the guidance be kept fairly short, perhaps 20 pages, in order to facilitate quick reference. The guidance should consist of three sections: an introduction, a matrix of public involvement techniques, and an attachment with additional reference information.

The introduction should lay out both the purpose and limitations of the guidance. The introduction should also:

- Encourage all stakeholders—regulators, facilities, and communities—to take an active role in opening up the permitting process and promoting meaningful public involvement;
- Urge industry and communities to explore innovative public involvement programs, such as the Responsible Care Program (through CMA) and Good Neighbor Agreements (through the Good Neighbor Project); and
- Encourage regulators, facilities, and communities to coordinate public involvement activities across media programs whenever appropriate and feasible.

The matrix of public involvement activities should list a wide variety of public involvement techniques, and provide a brief description of the activity (technique), and some of its advantages and disadvantages. Any activity currently required by an EPA Program office will be footnoted as a regulatory requirement. Since final recommendations regarding alternatives to individual permits have not yet been implemented, the easy-reference guidance should not attempt to ''tier'' public involvement activities by type of permit. The guidance should, however, have a mechanism to help people determine what activities they could use.

For its ''first edition,'' the guidance should identify ''Level I'' and ''Level II'' activities. Level I activities are those that should be considered for use in every situation, regardless of the type of permit, type of facility, or level of community interest. Level II activities represent a variety of ways to go beyond basic approaches to public involvement, and should be considered for use as necessary to meet the needs of the situation at hand. When developing subsequent editions of the easy-reference guidance, the mechanism for ''ranking'' activities (i.e., Levels I and II) should be re-evaluated to determine if it is still appropriate or if it should be replaced.

The attachment for additional resources should include: (1) the main telephone numbers of all State environmental permitting agencies; (2) the main telephone numbers of all EPA regional permitting offices; (3) a list of all the EPA-sponsored hotlines and information centers, and (4) a recap of the activities required by each EPA media Program office and a list of resources (e.g., guidance manuals) available through those offices.

Implementation: The RCRA Permits Branch in the Office of Solid Waste should take the lead on developing the initial edition of the easy-reference guidance. A draft of the guidance should be shared with a PIT workgroup for review and comment, as well as with the Siting and Public Participation Subcommittees of the National Environmental Justice Advisory Committee (NEJAC).

Hardcopy Distribution: The PIT should distribute copies to its stakeholder mailing list. The PIT should

also provide camera-ready copies of the guidance to the Office of Communications, Education and Public Affairs (OCEPA) and to the Office of Regional Operations, State/Local Relations (OROSLR) so they may distribute the guidance to their respective contacts and mailing lists. Furthermore, each media program office at the federal, state, local and tribal levels should also be encouraged to distribute the guidance as widely as possible.

Electronic Distribution: The Enhanced Public Participation Task Force leader should coordinate with appropriate Agency personnel to post the easy-reference guidance on the Internet. Access to the guidance should be provided through EPA's home page as well as through each media office's menus.

Training: The Enhanced Public Participation Task Force should coordinate with the Training Task Force to evaluate potential ways to provide training, if necessary, on techniques included in the easy-reference guidance.

2. Utilize the Environmental Justice (EJ) Public Participation Checklist as Guidance to the Extent Appropriate and Feasible

Description: The environmental justice movement has sparked a lot of discussion on ways to improve communications and working relations among agencies, industries, and communities. The InterAgency Working Group on Environmental Justice, led by EPA, developed a Public Participation Checklist that lays out ways to identify, inform, and involve stakeholders (e.g., environmental organizations, business and trade associations, civic/public interest groups, grassroots/community-based organizations, tribal governments, and industry). It reflects a combination of: guiding principles for setting up and conducting activities, such as public meetings; specific activities for ensuring widespread and meaningful involvement; and recommendations on how to effectively carry out those activities.

Although the checklist was initially developed in the context of environmental justice, to help federal agencies prepare for the first public meeting to discuss their EJ strategies, it embodies sound principles that apply to public participation for all communities. Therefore, the Task Force recommends that:

(1) EPA (through its Office of Communications, Education, and Public Affairs) should widely distribute the EJ checklist for use as guidance, so that permitting agencies, businesses and the public may benefit from it.

(2) A PIT workgroup continue to coordinate with the Office of Environmental Justice (OEJ) and the InterAgency Working Group on Environmental Justice in order to promote consistency in Agency approaches to enhancing public involvement. The Task Force should forward any suggestions it receives for modifying or enhancing the EJ Checklist to the OEJ and/or InterAgency Working Group.

Implementation: Public Participation Task Force representatives should meet with contacts in OEJ to: (1) review and discuss suggestions the PIT received regarding the Checklist, (2) develop an introduction to accompany the Checklist (describing its origins, etc.), and (3) to plan for further interactions between the two groups. Any changes to the Checklist should be made by OEJ or the InterAgency Working Group, since they originated the Checklist. Their continued ''ownership'' of the Checklist, and our combined efforts to keep the list current, will help ensure that the two teams continue to work in partnership to address environmental justice concerns, particularly in the context of public involvement. If OEJ (or the InterAgency Working Group) chooses to revise the Checklist, a PIT workgroup could provide assistance.

Hardcopy Distribution: Once the list is revised, OEJ should provide a camera-ready copy of the Checklist to the Office of Communications, Education and Public Affairs (OCEPA) for distribution to its contacts and mailing lists. In addition, camera-ready copies should also be provided to the Office of Regional Operations, State/Local Relations (OROSLR) so they can distribute the Checklist to their contacts and mailing lists. Finally, each media program office at the federal, state, tribal and local levels should be encouraged to distribute the Checklist as widely as possible.

The Task Force assumes that OEJ sends the checklist out to its contacts across the country, and that these contacts include EJ and community groups. In order to target industry for receiving copies of the Checklist, OEJ should provide the Checklist to trade associations for distribution to their member companies.

Electronic Distribution: The Task Force leader should coordinate with appropriate Agency personnel to post the EJ Checklist on the Internet. Access to the Checklist should be provided through EPA's home page as well as through each media office's menus.

3. Develop an Inventory of Mechanisms That Promote Access to Environmental Information

Description: Access to information is an essential component of public involvement. Meaningful, quality information is needed by regulators, regulated industries, and the public alike in order to promote sound environmental decision-making. Within the federal government, offices are revisiting what types of information should be collected and how information may be more readily shared.

An inventory with abstracts of existing sources of information, as well as of the efforts underway to improve quality of and access to information, and the appropriate contact person or office for each, would be a useful reference document. It could be used to inform agencies, businesses and the public of the wide variety of mechanisms available to them.

Development: The inventory of mechanisms should be developed under the direction of EPA's Office of Information Resources Management (OIRM). Identifying and describing the numerous and diverse data systems, information sources, and so on is beyond the scope of PIT resources; however, a PIT workgroup should meet with OIRM to discuss the project and to be available to provide assistance on an as-needed basis.

Primary focus of the inventory should be on Agency automated sources of information (e.g., data systems, bulletin boards), ''hardcopy'' information sources (e.g., Toxic Release Inventory (TRI) Report), and means of accessing information sources (e.g., through the Freedom of Information Act (FOIA) process, the Internet, via the National Technical Information Service—NTIS). The inventory should also, to the extent possible and feasible, discuss efforts-in-progress (e.g., the Key Identifier and One-Stop Public Access and Reporting Initiative). The inventory should include innovative systems promoted by Program offices to improve community involvement and help empower communities (e.g., Landview II being used by the Office of Solid Waste and Emergency Response). Finally, the inventory should include mechanisms to obtain access to pollution prevention information, such as on-line EPA computer systems like Enviro$ense or the Technology Transfer Network.

The inventory of mechanisms should be presented in an understandable, user friendly manner. In addition, because not every agency, business and member of the public will have electronic access

to bulletin board systems and the Internet, proposals for increasing access to information should also include making material easily available in the traditional manners (e.g., printed copies at agency offices, in information repositories, mailed to interested parties, announced in press releases or through radio ads).

Distribution: Distribution of the inventory should be coordinated by OCEPA. The inventory should be available in hardcopy format as well as through the Internet.

In addition, OCEPA should investigate more effective ways to publicize the many sources of information the Agency has, and the avenues to obtaining that information. For example, the Agency develops a thick (over 600 pages!) publication entitled ''Access EPA''—a comprehensive directory with detailed descriptions of the Agency's information resources. Unfortunately, relatively few people know of, or have access to, ''Access EPA.'' OCEPA should look into the feasibility of using innovative mechanisms to more widely and effectively distribute this directory, such as entering into an agreement with a national bookstore chain to get their stores to carry ''Access EPA'' and/or certain other EPA publications.

4. Explore, and Possibly Conduct Pilots for, the Development and Use of Comprehensive Multi-Media Community Involvement Plans

Background: Under the Agency's current regulations, there are various public participation requirements in each media program area—hazardous waste, water, and air. The requirements focus on the individual media permit, and are not consistent across programs. In meeting their regulatory obligations for each media permit, industries and regulators alike often create more confusion than clarity among members of the public who, for the most part, do not segment their involvement along statutory lines—their interests lay with the facility in its entirety. Moreover, having to conduct multiple, yet similar, activities (e.g., one public hearing for the air permit and another for the RCRA permit) imposes an unnecessary burden on a facility; having to keep track of and attend these multiple activities imposes an unnecessary burden on the public. Further exacerbating the problem is the way information about a facility is collected and reported—also a media-by-media approach. No clear picture of the facility as a whole, its total emissions or releases, its comprehensive compliance record, is readily available.

Discussion: In order to create an environment that truly fosters effective interactions between facilities and their neighboring communities, the Agency needs to make the entire public participation process more user-friendly. Using Community Involvement Plans (CIPs), in concert with some programmatic adjustments from other PIT Task Forces, could accomplish this objective.

It is envisioned that a facility, in close coordination with community stakeholders, would be responsible for drafting a CIP. The elements of a CIP would most likely vary, although certain core elements may ultimately be defined. In essence, the CIP would serve as a vehicle through which a facility and a community could form a multi-media approach tailored to meet their particular situation. They could address issues on an aggregate basis, instead of on the media-by-media basis perpetuated by EPA's current structure and regulations. At a minimum, a CIP should set objectives for educating the community on the facility and its operations and for providing routine opportunities for information exchange. Techniques to achieve these objectives could include: community advisory panels, facility tours, integrated compliance reporting, and so on.

The appropriate role of the regulatory agency would also need to be laid out in the CIP. There would need to be an incentive offered in exchange for a facility undertaking the integrated approach to public involvement embodied by the CIP concept—for example, expedited permit processing, aggregated (multi-media) permit processing, or relief from media-specific public participation regulatory obligations. This does not mean, however, that the regulator does not continue to play a key role—the permitting agency would need to interface with both the facility and the community.

Implementation Ideas: The Task Force recommends that the CIP concept be piloted with a few facilities and their neighboring communities. It may be possible to coordinate this effort with other Agency initiatives, such as Project XL or Brownfields, that are intended to pilot innovative approaches to environmental management. The PIT could take the lead on evaluating the results of the pilots. If the efforts prove successful, the Agency should promote widespread use of CIPs and pursue the regulatory changes needed to implement the incentives described above.

- Pros—There are many potential benefits to be gained by using CIPs. For example, they move us away from a ''command and control'' approach by allowing flexibility to follow a plan that makes sense for the situation at hand. If CIPs ultimately replace media-specific public participation requirements, there would still be a basic ''level playing field'' by virtue of the fact that everyone would have to develop a plan founded on mutual (facility, community, regulator) needs and concerns. Finally, CIPs enable a facility and a community to deal with issues on an aggregate basis, which may help to move EPA towards a more integrated approach to environmental management.

- Cons—Providing some relief from current media-specific public participation requirements in exchange for using CIPs will necessarily result in a lack of consistency in approaches to public participation. The lack of consistency could create confusion for industry, communities, and regulators alike—no one would be certain what they should do or what their opportunities for involvement are. In considering this aspect, however, it is important (1) to remember that there is already inconsistency in public participation requirements across the Agency's media programs; (2) to question whether the desire for consistency outweighs the need for flexibility; and (3) to focus on the need for improved results.

5. Develop a Series of Case Studies on the Effectiveness of Public Participation Activities

Description: Guidance materials and checklists for promoting public participation provide very useful tools. However, there is a lot that can be learned from real world successes and failures as well. A compilation of actual case studies would be a useful tool to help permitting agencies, industry, and communities put suggested public involvement activities into a context meaningful to their own situations—in other words, it gives people something concrete they can relate to.

Development: The Task Force recommends that a PIT workgroup compile a number of case studies as a project in FY 1996. The PIT should collect existing case studies from various sources, such as (but not limited to) EPA Program offices, Regional or State community relations offices, and environmental justice groups. Further, the PIT could develop its own case studies based on recommendation 4, above.

PERFORMANCE MEASURES—TASK FORCE RECOMMENDATIONS

Background

An important aspect of improving the environmental permitting process concerns how the performance and success of the permitting programs are measured. To often in the past, regulatory agencies have measured success based on the number of permits that have been issued. This ''bean counting'' has been identified as one of the problems in the current system that needs to be improved.

On September 11, 1993, President Clinton signed Executive Order 12862, Setting Customer Service Standards. This Order, in part, requires each department and agency to ''post service standards and measure results against them''. The performance measures presented below have been prepared to comply with the Executive Order. These measures will be publicly available so that all Agency stakeholders can review the performance of the permitting programs.

The Performance Measures Task Force developed the following performance and tracking measures based on the input received at stakeholder meetings held during the PIT project and the written comments received on the draft recommendations. The performance measures will be used to evaluate how a permitting program is doing in achieving environmental results and customer satisfaction. The measures focus on the performance of the permitting process and are designed to evaluate the system as a whole. These measures will help EPA identify where changes may be needed in a program to achieve the desired results. The tracking measures provide information on changes to the permitting processes over time and will be used to identify areas of opportunity for process improvement.

The performance and tracking measures are broken down into the following three categories:

1. Process—those measures that specify how the permitting process is doing compared to established criteria;
2. Results—those measures that determine whether the permits are having their desired outcome; and
3. Customer Service—those measures that evaluate how the general public and regulated community feel about the permitting process.

It is recommended that the performance and tracking measures be piloted in a Region that is still issuing a significant number of permits. This will allow the measures to be field tested and any modifications made prior to full implementation. The Permits Improvement Team would assist the Regional office as necessary.

It is further recommended that each Regional office provide these measures to any state, tribe or local government, that is authorized to issue permits, for their consideration. These permitting authorities should not be required to adopt these measures. They should be free to modify them or develop their own measures of a successful permitting program.

Generic Performance Measures

Process

1. Timeliness

Each Regional office that is issuing permits will establish processing time goals for each type of permit they issue (presented as a percentage of applications processed within a specified timeframe). Each Regional media permitting program will determine the appropriateness of dividing their permit universe based on the degree of environmental impact (e.g. minor, significant minor, major). Four distinct processing times will be established to cover the entire permitting process, from receipt of application to permit effectiveness. In addition, the total processing time of each permit will be a tracking measure.

Example: For (type of permit [1]), the time required from receipt of an application to agency determination that the application is complete is as follows:

____% determinations made within 30 days;
____% determinations made between 30 and 60 days;
____% determinations made between 60 and 90 days.

For (type of permit [1]), the time required from receipt of a complete application to issuance of the proposed (or final if no public comment is necessary) agency decision to approve or deny the permit is as follows:

____% proposals/decisions made within 60 days;
____% proposals/decisions made between 60 and 90 days;
____% proposals/decisions made between 90 and 180 days.

For (type of permit [1]), the time required from the issuance of the proposed decision to approve or deny the permit to the final agency action is as follows:

Where limited and straightforward comments are received and no public hearing:

____% decisions made within 60 days;
____% decisions made between 60 and 90 days.

Where substantial and complex comments are received and no public hearing:

____% decisions made within 90 days;
____% decisions made between 90 and 120 days.

When a public hearing is held:

____% decisions made within 180 days;
____% decisions made between 180 and 240 days.

For (type of permit [1]) that are appealed, the time required from issuance of the Region's final permit decision to the effective date of the permit is as follows:

____% effective within 90 days;
____% effective between 90 and 270 days;
____% effective between 270 and 455 days;
____% not effective within 455 days.

Purpose: To have the Regional offices focus on each step of the permit process. The time required to process a permit is influenced by the performance of both the regulatory agency and the permittee as well as by the level of public comment. To achieve the most rapid processing of a permit as possible the agency and permittee need to work together (and with the public as necessary). Therefore, this performance measure is written to identify how long the permit process is taking for each of the major steps. If the actual processing time of the Regional office is longer than the established goal, steps can be identified to improve the performance in that area.

2. Number of Pending Permits

Each Regional office that is issuing permits will establish a goal for the maximum number of permits for new discharges, emissions or releases (either new facilities or modifications required to address a new discharge at an existing facility) that have exceeded the specified times for approval or disapproval provided in 1 above.

Example: (#) of new applications and permit modifications for (type of permit [1]) have not been approved or disapproved within the ____ days set as the maximum for this type of permit action.

Purpose: To provide a measure of the number of permits for new discharges that have not been processed within the defined time periods. This performance measure is just for new discharges. Backlogs of permit renewals are a tracking measure (see below), since there may be a need to prioritize the issuance of certain renewals (e.g. ecosystem based priorities) rather than renew a permit after it has expired but remains in effect. Trend analyses would

allow the regulatory agency to readily determine whether they are improving or falling further behind. A backlog above the goal would trigger an evaluation to determine its cause and how to improve the Region's performance.

Results

1. Environmental Indicators

The success of permitting programs need to evaluated based on the environmental conditions that exist in a particular area. Although permitted discharges are not the only source of pollutants, they are regulated to limit their impact so that environmental goals are achieved. Therefore, it is recommended that all permitting authorities develop specific environmental indicators that will be used to evaluate the overall success of their permitting programs.

The Agency is in the process of developing environmental indicators for the nation. Once the national indicators are determined each Regional office will work with the respective state and tribal governments to establish specific indicators for that jurisdiction. This is being accomplished through the development of Environmental Performance Agreements (EnPA) with states and tribes. EnPA's will include indicators that will be re-evaluated yearly and updated, revised or replaced as needed to accurately measure environmental progress. The first EnPA's will be for states and tribes volunteering in Fiscal Year 1996, with full implementation scheduled for FY97. A key component of the EnPA's is stakeholder participation, which includes the development of appropriate environmental indicators for each jurisdiction. The environmental indicators will be used to determine priorities for the next year, including permitting activities.

2. Level of Compliance

The compliance status of all permitted facilities is an important performance measure for permitting programs. In order for environmental protection to occur, facilities must be in compliance with their permits. Just issuing the permit doesn't ensure protection, therefore, it is necessary to determine the level of compliance with those permits to help identify where greater clarity of permit conditions is needed and where to provide technical assistance.

The initial PIT recommendations on how to measure the level of compliance did not contain sufficient detail to allow stakeholders to give their opinion on this approach. The comments received focused on the need for more detail to better define this performance measure. In addition, the Agency has compliance categories for the individual media programs. However, for the most part these have not been developed with stakeholder input. Therefore, it is recommended that a project team of EPA Headquarters and Regional offices and state and tribal agencies be established to further develop this measure as needed. The project team would work with stakeholder groups in the development of a proposal to measure the level of compliance of permitted entities and identify the causes of non-compliance. The Office of Enforcement and Compliance Assurance (OECA) should be responsible for establishing and leading the broad based project team.

Customer Service

1. Customer Satisfaction

Customer service surveys and standards have been drafted for three groups to which EPA provides service: citizens participating in the permitting process; permit applicants; and authorized state, tribal or local governments. The surveys have been approved by the Office of Management and Budget (OMB) and EPA plans to begin using the surveys in FY'96. The customer service standards will be discussed with stakeholder groups prior to finalization. EPA will prepare a report on the results of the customer service surveys in September 1996.

The Office of Policy Planning and Evaluation (OPPE) has been recommended to conduct the surveys and analyze the results. Each Regional permitting office would receive a report identifying any situations where the customer service standards were not met. In these cases, the Regional office could hold focus group meetings or other outreach activities with appropriate stakeholders to determine a course of action that is intended to improve customer service.

Generic Tracking Measures

Process

1. Time Required for Permit Issuance

Each Regional office that is issuing permits will determine the average time required from receipt of a permit application to the Region's final permit decision (this does not include the time to address any appeals). The range of time required to issue each type of permit will also be determined. This information will be made available in any fact sheets and permit application information distributed by the Regional office.

Example: The average time required to issue (type of permit [1]) is ____ (days, weeks, months) with a range of ____ to ____ (days, weeks, months).

Purpose: To provide the applicant and public with an estimate of the total time required to process a given type of permit. This measure, coupled with the timeliness performance measure will show the amount of time the applicant spends working on the permit as well as EPA.

2. Permit Application Completeness

Each Regional office that is issuing permits will track the number of resubmittals (additional/revised information required for the permitting authority to be able to act on the application) required to obtain a complete application. This information will be presented as a percentage of the total universe of permit applications received.

Example: The percentage of (type of permit [1]) applications requiring resubmittal prior to being complete is as follows:

____% No resubmittals required
____% One resubmittal required
____% Two resubmittals required
____% Three or more resubmittals required

Purpose: To have the Regional offices track and make public the number of resubmittals needed to obtain a complete permit application. Regional offices should work with their regulated community to identify causes of excessive resubmittals and determine corrective actions. Permitting programs with high percentages of applications requiring multiple resubmittals would indicate a problem somewhere in the permit process. This could include the information being requested, the clarity of the deficiency letter, the training provided to the regulated community, etc. Trend analysis could be used to determine if progress was being made to reduce the number of applications requiring resubmittal.

3. Cost of Permitting Program

Each Regional office that is issuing permits will estimate the total agency work hours required to process each type of permit they issue and the average number of work hours required to process each individual permit. This information will allow the EPA Region to sum the totals from each permit category to obtain the overall work hours expended on environmental permitting in that Region.

Example: The total work hours of processing all (type of permit [1]) was (#)

for ____ (calendar or fiscal year). The average work hours expended on each permit, based on the processing of (#) permits, is (#) for the same reporting period.

Purpose: To provide an estimate of the total work hours expended on environmental permitting programs. The average work hours information would be useful in determining if programs of similar complexity had significantly different averages. This information could also be used to compare the average processing times of the Regional offices. Evaluations could then be conducted to determine the cause of the difference and learn from successful programs. Trend analysis could be used to determine if work hours are increasing or decreasing.

4. Number of Pending Renewal (Air/Water) and Interim Status (RCRA) Permits

Each Regional office that is issuing permits will track the number of permits that have expired but remain in effect and have not been renewed, or in the case of RCRA, the number of facilities that are operating under an interim status designation.

Example: (#) (type of permit [1]) have not been renewed by the expiration date as of _____ (reporting period).

Purpose: To provide a measure of the number of permits that have not been renewed by their expiration date. Trend analyses would allow the Regional office to readily determine whether the number is increasing or decreasing. Additional analysis would be needed to determine if an increasing trend was a problem or the result of a decision by the Region to focus on ecosystems and allow permits in non-priority areas to remain in effect.

Results

1. Pollution Prevention/Innovative Technology

Each Regional office that is issuing permits will track the number and percent of their permits that include innovative technology or pollution prevention conditions that are included as a means, in whole or in part, to achieve compliance. These conditions could include actual pollution prevention activities or investigations into possible pollution prevention techniques that could assist the facility in complying with permit conditions. Discharge, emission and release limitations would not be considered pollution prevention conditions. The Regions would require the same information from delegated state, tribal and local agencies.

Example: (#) and (%) of (type of permit [1]) that includes pollution prevention conditions (this term requires definition) in the permit as a means, in whole or in part, to achieve compliance with permit conditions.

Example: (#) and (%) of (type of permit [1]) that utilize innovative technology (this term requires definition) to achieve compliance with permit conditions.

Purpose: To determine the effectiveness of permitting programs in encouraging the use of pollution prevention and innovative technologies. If the percentage is below what a regulatory agency was hoping to achieve, additional analyses could be conducted to determine why pollution prevention approaches or innovative technologies were not being used to achieve permit compliance. This tracking measure should be reevaluated, within 1–2 years, to determine if it should be changed to a performance measure, with a specific goal as to the percentage of permits that should utilize pollution prevention techniques or innovative technologies to achieve compliance.

POLLUTION PREVENTION INCENTIVES—TASK FORCE RECOMMENDATIONS

A. Background/Approach

The Pollution Prevention Incentives Task Force derived its mission from the recommendations of the National Performance Review (NPR). The NPR stated that EPA should encourage pollution prevention (P2) by providing flexibility, creating P2 incentives in permits and compliance approaches, and issuing guidance on how to implement innovative strategies and procedures. The NPR also recommended that EPA facilitate permitting of innovative technologies and identify what changes are necessary to achieve this.

EPA has a strong commitment to fostering pollution prevention because experience has shown that it is good for the environment and the economy alike. To implement P2 on a larger scale calls for flexible thinking, concrete and ambitious goal-setting, strong commitment at all levels of government and industry, and an innovative effort that only business can supply. The P2 Incentives Task Force explored these dynamics to help EPA improve the permitting system to encourage investment in P2 measures.

[1] Type of Permit—Each permitting authority would individually define the permit universe that would be included within the performance or tracking measure.

The Pollution Prevention Act of 1990 establishes a hierarchy for environmental protection (source reduction, reuse, recycle, treat, store and dispose) with P2 as the preferred approach. As the hierarchy acknowledges, P2 approaches are not attainable in all instances. In the discussion that follows, many of the recommendations are relevant to P2, recycling, or other innovative approaches.

Streamlined permitting may have an important role in fostering P2. The PIT is focusing on eliminating factors of the permitting system that are overly rigid, cumbersome, and time-consuming. These changes can free up additional resources for potential investments in P2. Yet, streamlined permitting might not mean more pollution prevention unless we also allow greater flexibility, and design incentives to encourage P2-based activity.

This Task Force is emphasizing *incentives* for P2 because, as a general rule, it is in industry's interest to prevent pollution. Our goal is to create permitting incentives and eliminate barriers for industry to do what is largely in their own best interest.

The following Task Force recommendations present approaches for forging the necessary connection between more efficient permitting and real progress in preventing pollution.

B. Task Force Recommendations

1. Link Performance-Based Permitting with Facility-Based Permitting, Consolidation of Permitting Requirements, and Cross-Media Permitting

The Task Force recommends that EPA and state, tribal and local permitting authorities use performance-based permitting as a means of achieving greater flexibility. By performance-based permitting, the Task Force means permitting which recognizes that a standard containing a numeric level does not automatically dictate which technology facilities are to use. On the rule development side, this means writing standards that set numeric levels where possible and appropriate. Many EPA technology-based rules have in fact been written that way. This is because ''technology-based'' is short-hand for a rule that sets a standard at the numeric level at which the referenced-technology performs. The reference technology is determined by the type of standard being set, such as best demonstrated available technology.

What is key is how ''technology-based'' rules are interpreted by permit writers. Often, they interpret the rules as

requiring the use of the referenced technology. To avoid this, EPA rulemakings should explicitly acknowledge that permit writers are authorized to evaluate technologies other than the referenced technology. Flexibility is needed to allow facilities to use innovative approaches that prevent pollution and achieve greater emission reductions across media. Flexibility would not be allowed to compromise environmental protection, since the permit writer would still have to be satisfied that the permit applicant could meet the performance standard in question.

It is key to recognize that permit writers are generally burdened with heavy case loads, and that it substantially increases their burden if they must regularly evaluate alternative technologies to determine whether they perform at a level equivalent to that of the standard's reference technology. Making it easier for permit writers to evaluate alternative technologies is a task that EPA and state, tribal and local permitting authorities need to address systemically. Hopefully, some of the specific steps provided at the end of this section will meet this need.

The steps in this recommendation should provide the following advantages: (1) making it easier for facilities to use innovative technologies (often key for P2); (2) giving facilities more latitude to explore P2 approaches; and (3) giving facilities a greater economic incentive to explore P2 approaches. Looking at a facility as a whole, rather than a collection of individual pipes each of which needs to meet an individual emission level, can often provide significantly greater opportunities for preventing pollution and making wise investments that yield long-term savings.

The Task Force recommends that EPA, state, tribal and local permitting authorities take steps to link performance-based permitting with facility-based permitting, consolidation of permitting requirements by industry sector, and cross-media permitting. These recommendations build on the Administrative Streamlining Task Force's recommendation for flexible permitting. It is important to note that the focus here is on facility-based permitting, and not company-based, which is a different issue.

These steps are also in line with the alternatives being explored in a host of new EPA initiatives, including several priority projects of the Administration's program to reinvent environmental regulation. Project XL, and alternative strategies for industry sectors, communities, and federal agencies, can address a combination of facility-based permitting and cross-media permitting issues; consolidating federal air rules for the chemical industry will be a test case for consolidation. Demonstration projects in multi-media permitting, as led by the Pollution Prevention Policy Staff are expected to produce several multi-media P2-oriented permits in the next year. The Environmental Technology Initiative's (ETI's) Innovative Technology Permitting Program, being implemented by the Office of Policy, Planning and Evaluation, is currently advancing over two dozen projects designed to eliminate barriers to technology innovation in the permitting process. In addition, ETI's Environmental Technology Verification Program, being implemented by the Office of Research and Development, will soon begin providing credible performance information on more cost effective innovative technologies.

Based on the foregoing, the Task Force recommends the following:

a. The concepts of this first recommendation should be incorporated into CSI, Project XL, ETI, and multi-media permitting. PIT members will work with these initiatives to help achieve the implementation of these concepts.

b. As Regional offices disinvest from oversight of state permit programs, they should collaborate with state, tribal, and local permitting authorities in assessing relevant P2 techniques, where appropriate.

c. To the extent possible, subsequent EPA rulemakings should explicitly acknowledge that permit writers are authorized to exercise their judgment in establishing performance-based limitations based on the technology referenced in the development of the regulatory standard. For example, in the NPDES program, the permitting authority does not approve technologies. The permit writer prepares a permit which includes limitations and conditions, and it is up to the facility to determine how they will meet the permit limits.

d. Examine what steps would be necessary to move towards institutionalizing some of the approaches described above in core EPA programs. This should be undertaken by a PIT workgroup.

e. State permitting authorities should use the results of the Environmental Technology Verification Program or similar state programs to reduce the need for testing and indepth engineering review during permitting.

2. Create Industry-Sector Inventories of Regulatory Thresholds for Permitting.

The Task Force recommends developing a public inventory of existing federal regulatory thresholds for permitting requirements on an industry-by-industry basis. Specifying the thresholds would help facilities to assess the costs and benefits of going below the thresholds and opting out of the permitting system. The Task Force believes that in most instances the savings achievable by getting out of the permitting system would more than offset the investments needed to get releases below thresholds.

Data in this inventory could serve as a reference point for discussions between communities and local facilities about financial incentives for using pollution prevention approaches. Mutual discussions could more easily be tied to the financial incentives for a facility to reduce releases to a level where permitting is reduced or unnecessary, and outcomes that could represent cost savings to the facility.

The Office of Pollution Prevention and Toxics (OPPT) in EPA is piloting this approach for the metal finishing industry, which is comprised mainly of small to medium-sized businesses. Since industry faces federal and state regulations, OPPT will try to include key state regulatory requirements, too. If it appears that some opportunities for getting below certain thresholds bear more promise than others, EPA would emphasize those opportunities most likely to result in success.

EPA recognizes that some explanation about possible permit variances or exemptions will be needed in an industry-sector inventory. In some instances, for example, emissions trading is allowed, and a facility may have legitimately purchased an emissions trading credit. EPA will need to provide sufficient explanation so that users of the inventory will find its data relevant and meaningful to their own applications.

To be clear, the scope of an inventory will be limited to linking permitting thresholds with the economic incentives for getting below thresholds. It will not provide facility-specific information or health/environmental effects data.

The Task Force's specific recommendations are:

a. OPPT should develop a pilot inventory for an industry sector, such as metal finishing (this effort has already started).

b. OECA and OPPT should investigate whether OECA industry sector notebooks (developed for compliance assistance) could be used as a basis to

help industry conduct analyses between the costs of compliance and the costs of getting below permitting thresholds.

3. Explore Offering Alternative Emissions Tracking in Exchange for Using P2 Practices

The Task Force recommends that EPA explore whether an alternative emissions tracking approach could be offered in exchange for a facility commitment to use P2 practices to achieve compliance in whole or in part. Federal permitting requirements generally require facilities to monitor releases (using EPA-approved methodology) and report this data to regulatory agencies. An alternative approach would be to allow a facility to use third-party auditors to convert its proprietary process control measurements into release data that would be reported to EPA as public data.

A primary reason EPA is interested in this approach is that using process data encourages facilities to find opportunities for pollution prevention. Second, it may provide communities with significantly more reliable data on facility emissions in their communities. Third, there may be a significant economic incentive for industry to avoid the cost of expensive monitoring equipment.

The recommended approach is basically an equivalent alternative to current monitoring requirements. (Reducing monitoring requirements is beyond the scope of this particular recommendation.) The Task Force acknowledges that EPA would need to verify P2 commitments made in exchange for using this alternative.

EPA recognizes that there are some concerns about whether the public would have confidence in this recommended approach. One concern is that industry consultants might lack credibility with local communities. The key difference in what the Task Force is proposing is that industry would not pay a third-party auditor directly. The apt analogy is the third-party auditor system used in this country for accrediting laboratories. Labs pay a non-profit organization for the services of the third-party auditors. The auditor's sponsoring organization (the non-profit) has an overriding interest in maintaining the integrity and independence of their auditors, because a biased auditor reflects badly on the organization and the entire accreditation system.

Third-party auditors would have to be trained and accredited by an accrediting organization. Among other things, they would probably need to be trained in knowing what kind of data to get from facilities, and learning the calculations to perform to convert facility process data into reportable emissions data. Given the great diversity of American industry, this may be an idea that could be piloted on an industry-sector basis.

The Task Force recommends the following specific steps:

a. A PIT workgroup should consult with the project team for piloting third-party audits for industry compliance (one of the President's 25 initiatives for reinventing environmental regulation) to further investigate the viability of this approach.

b. This PIT workgroup should also explore potential overlap with International Organization for Standardization (ISO) 14000 efforts.

4. Share P2 Data With Permit Applicants and Affected Communities, and Give Basic P2 Training to Permit Writers

The Task Force recommends that EPA and state, tribal and local permitting authorities share P2 data with permit applicants and affected communities, and give basic P2 training to permit writers. Both of these ideas would provide a way for P2 to be emphasized up-front in the permitting process.

Most permit writers are at the state, tribal, and local level and face workloads that are generally perceived as heavy. To date, their experience with P2 has ranged from no involvement to personal commitment to P2, with lack of time and knowledge often being cited as barriers to their promoting P2.

Despite this perception about the difficulty permit writers face in promoting P2, a recent survey of permit writers in northeastern states conducted by the Northeast Waste Management Officials' Association (NEWMOA) indicates the vast majority of those surveyed wanted P2 training. They said they wanted training in when, how, and where they can use P2 directly in their jobs, and under what authority they can act. NEWMOA is piloting a P2 training for permit writers, based on a review of many permits where P2 has already been incorporated. Efforts such as NEWMOA's could serve as a model for training in other parts of the country, and could be tailored according to the permitting authority and regional needs.

At a minimum, permit writers could serve as a reference for facilities on where to turn (such as local technical assistance centers) for P2 information. It is key that they have a baseline of information about P2 concepts and appreciate the value of sharing P2 data with facilities. Training could most effectively be offered at the state and EPA regional level. EPA, in consultation with states, tribes and local permitting authorities, should evaluate whether P2 reference materials need to be developed and sent to permit applicants and made available to the public.

The Task Force recommends that pollution prevention be made part of the core training for permit writers being advocated by the PIT Training Task Force. Stakeholders have suggested that P2 training should also be given to enforcement and regulatory personnel.

5. Develop an Enforcement Policy to Accommodate the Possibility That Innovative P2 Technologies May Not Perform as Expected or May Take Longer to Achieve Compliance

The Task Force believes it is key to examine the current incentives and disincentives for pollution prevention in environmental enforcement policies as well as in permitting. One reason is that innovative P2 technologies do not always perform as expected. A facility may have little incentive to invest in an innovative P2 technology—and risk its compliance on how that technology will perform—if there is no ''soft landing'' enforcement policy to cushion against enforcement penalties in the event the technology fails to perform as expected. Some form of risk-sharing, such as mitigation of penalties, should be accepted by EPA.

A second reason that enforcement policies are key to encouraging P2 through permitting is that using P2 approaches—such as process changes—sometimes takes longer than using off-the-shelf control devices. If EPA can offer no extension in compliance deadlines (as appropriate for making P2 changes), facilities may opt for using control devices to ensure they meet these deadlines.

The Task Force recommends that the PIT and the Office of Enforcement and Compliance Assurance (OECA) establish a workgroup to explore a ''soft landing'' enforcement policy for facilities that adopt innovative P2 technologies, including those verified by EPA or states, that fail to perform as expected. A soft landing policy could remove a significant disincentive against using innovative technologies by providing a cushion against enforcement penalties or costly remedial solutions, and allowing a facility some flexibility in reaching compliance. For example, a facility might be allowed time to achieve compliance through adjusting some other part of its process, allowing it to keep its P2 technology intact.

In addition, the workgroup should identify more ways to offer compliance extensions, consistent with statutory

compliance extension mechanisms, in exchange for commitments to use P2 approaches for compliance. (The Task Force supports EPA's recently initiated pilot efforts like Project XL that will be exploring this kind of an approach.) The Task Force also recommends that OECA and EPA Program offices consider using an approach developed by stakeholders in the Industrial Pollution Prevention Project (IP3): through rule-specific guidance, allowing permit modifications to be made under specified conditions that extend the time for compliance. This approach has received EPA-wide endorsement as part of the Clean Water Act reauthorization process.

The Task Force recognizes the need to address boundaries as to how ''soft'' a soft landing enforcement policy should be, and how long a compliance extension should reasonably be. EPA has previously explored these issues in the IP3, and will need to clarify them again. The State of New Jersey, through an Environmental Technology Initiative grant, will be exploring these limits in its own programs.

6. In All General Permits and Permits-By-Rule, Include Language That Explains the Preference for Using P2 Approaches and the Potential Economic Benefits of P2

The Task Force recommends that EPA and state, tribal and local permitting authorities incorporate language in all general permits and permits-by-rule that explains the environmental management hierarchy (source reduction, reuse, recycle, treat, store and dispose), the preference for using P2 to achieve compliance, and the potential economic benefits associated with P2. If there are differences between EPA's and a state, tribal or local permitting authorities' hierarchy, the permitting authority could list both.

Individual permits are not included in this recommendation because it is recognized that, in these cases, major opportunities for P2 can be identified while the permit conditions are being developed before permit issuance. Therefore, for individual permits, it would be better to put this type of language up-front in the process, such as in permit call-in letters or model permit applications used in the RCRA program. Also, implementing recommendation 4 would encourage including P2 up-front in the process of preparing individual permits.

It is recommended that a PIT workgroup develop sample language and make it available for distribution through core training sessions for permit writers. The workgroup should include permit writers from the Regions and state, tribal and local permitting agencies.

TRAINING TASK FORCE RECOMMENDATIONS

Background

The National Performance Review Team for Permit Streamlining identified training for permit professionals as a priority. Their specific recommendation included the following suggestions: establish an EPA Permits Institute, require State/Federal permit professionals to complete core curriculum, review permit organizational staffing for appropriate skills mix and provide financial/other incentives and awards to permit professionals. In addition to these specific proposals, training was also highlighted under the category of ''Increasing Access to Permitting Information.'' Suggestions under this category discussed training for the public and applicants. Specific recommendations included: draft clear, understandable guidance manuals for states, tribes, local authorities, applicants and the general public; and hold periodic training workshops in conjunction with state associations, trade associations and citizens' groups. The PITs Training Task Force chose to address training broadly to include the regulated community, public and permit professionals.

Overview

Effective environmental permitting relies upon effective transmittal and use of information by all interested parties. State, tribal, local and EPA permit writers need information of the specific characteristics of the facilities being permitted, and need knowledge of the applicable statutes and regulations. The regulated community also needs information, in particular of the permitting process and how regulators use their information. Citizens and environmental groups also need to know the permitting process in order to effectively participate in the permitting process.

The lack of information leads to several problems. Delays in completing permits occur if permittees and citizens do not understand the permitting process and use the appeals process to delay issuance until they are satisfied they fully understand all provisions of the permit, including how each provision was developed. Inconsistencies between permits, that should be similar, occur if permit writers do not understand the basis and reason of the underlying regulations or do not know of applicable guidance.

Recommendations

In order to provide the necessary information to EPA, state, tribal and local permit writers, the regulated community, and citizens and environmental groups, the Task Force recommends four actions.

1. Provide information to the regulated community and others. The Task Force recommends that EPA national Program offices use a series of informational tools to educate permittees and citizens about the permit process. Specific tools to be used or developed are:

a. Using the Internet, trade associations and small business development centers to announce training opportunities and distribute training materials. The announcement should include an explanation of the contents of the training. Program offices should also coordinate to standardize and post these announcements and develop and implement a program to educate the public on the permitting process using tools such as: press releases, infomercials, radio/TV announcements and commercials.

b. Development of a generic fact sheet which summarizes a new permitting project in plain English and may be used as a tool to explain to interested parties the permitting action. The Program offices should coordinate in the development of these fact sheets to achieve as much consistency in format and information provided as possible. After the generic fact sheet is developed, all permitting authorities should prepare a fact sheet, following the model, as part of the permitting process.

c. Develop a clearinghouse of existing model permitting applications and instructions (this should be accomplished in cooperation with state, tribal, and local associations). In addition, the Program offices should request the permitting authorities, especially in EPA, to use ''plain English'' instructions with application forms and to include a single point of contact (see Administrative Streamlining Task Force report).

2. Provide information on every new significant[5] *rule.* The Task Force recommends the development and use of a series of informational tools to educate Regional, state, tribal, and local permitting authorities, permittees, and citizens about the requirements and reasons for new rules. Specific actions are:

[5] A significant permitting rule should be determined by considering its environmental impacts, community concerns, and/or complexity of the regulated facilities.

a. Program offices should prepare, as part of regulatory development for significant rules, a package of information which explains the new requirements, including information about permitting and any implementing guidance. The information package should contain materials targeted to different audiences, the regulated community, the permitting authorities and the public and provide contacts for additional information. This package of information must be available at the time of promulgation (e.g., via Internet). Include in the Federal Register information about the availability of this material.

b. A PIT workgroup (including representatives from program the offices) should develop a standardized fact sheet format to be used with each new significant rule. Once developed, the Program offices should use this format for transmitting information about each new significant rule either electronically (e.g., Internet) and/or via mailing lists.

3. Define and provide training on core skills and knowledge needed to issue permits. The Task Force has developed the core skills and knowledge that are recommended for permit writers to be effective in their jobs. The Task Force recommends that the Administrator endorse a training program for permit writers, including the core curriculum for permit writers (listed below). This will require the commitment of resources to develop the training and travel funds to attend the training. A PIT workgroup (comprised of representatives from each Program office) should take the lead in designing the training program. States, tribes, and local permitting authorities should participate on the workgroup. Each Program office also needs to identify the additional media specific knowledge which would be necessary for that program. All training should be made available to interested parties, both internal and external to EPA. Examples of these core skills and knowledge include:

- The need and purpose of permits,
- Factors that comprise an enforceable permit,
- Applicable parts of the environmental statutes,
- When a permit application is complete,
- Pollution prevention and innovative technology,
- Waste management hierarchy,
- Development of permit conditions,
- Public speaking and communicating with different audiences,
- Technical writing,
- Sensitivity (understanding needs of stakeholders),
- Environmental justice,
- Holistic view of permitting—multi-media/coordination of permits, and
- Training on the new permitting approach (if adopted).

4. Store and provide critical knowledge. The Task Force has identified a series of tools to better provide written guidance and accumulated permitting office experience to Regions, states, tribes, local authorities, permittees, and citizens. The Task Force recommends that the national Program offices develop these tools and make them available as needed. These tools are:

a. Provide electronically (Internet) an index and synopsis of guidance documents.

b. Creation of EPA subject-based work groups, for example to coordinate issuance of combustion permits between the Air, RCRA and TSCA programs. To assist in the development of the subject based work groups, the Regions should establish regional multi-media permit coordination work groups. Representatives from the regional multi-media permit coordination work groups and the Headquarters Program offices will participate on the subject-based work groups. The work groups will focus on implementing more organized permit ''quality control'' (e.g., collecting, storing and disseminating EPA, state, tribal, local agencies, and permit writers appeal issues (major and minor) and/or other issues that have an impact on the effectiveness and enforceability of permits).

c. Establishing quasi-independent permit review teams to assure the issuance of quality permits. The review teams may consist of representatives from the above-mentioned, subject-based work groups. The review teams would evaluate significant permitting actions [6] to assure all aspects of the permitting process were addressed (environmental justice, pollution prevention, public notice/hearing, and understandable compliance terms). In FY–96, the permit review team and a state volunteer will conduct a pilot to assess the effectiveness of the permit review team.

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[6] A significant permitting action should be determined by considering the environmental impacts, community concerns, and/or complexity of the facility being permitted.

federal register

Friday
May 10, 1996

Part IV

Department of Health and Human Services

Food and Drug Administration

Harmonisation International Conference; Guidelines Availability: Biotechnological/Biological Pharmaceutical Products; Viral Safety Evaluation; Notice

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. 96D–0058]

International Conference on Harmonisation; Draft Guideline on Viral Safety Evaluation of Biotechnology Products Derived From Cell Lines of Human or Animal Origin; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is publishing a draft guideline entitled ''Viral Safety Evaluation of Biotechnology Products Derived From Cell Lines of Human or Animal Origin.'' The draft guideline was prepared under the auspices of the International Conference on Harmonisation of Technical Requirements for Registration of Pharmaceuticals for Human Use (ICH). The draft guideline describes viral safety testing and evaluation of biotechnology products derived from characterized cell lines of human or animal origin, and outlines data that should be submitted in marketing applications.

DATES: Written comments by August 8, 1996.

ADDRESSES: Submit written comments on the draft guideline to the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857. Copies of the draft guideline are available from the Division of Communications Management (HFD–210), Center for Drug Evaluation and Research, Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–594–1012. An electronic version of this guideline is also available via Internet by connecting to the CDER file transfer protocol (FTP) server (CDVS2.CDER.FDA.GOV).

FOR FURTHER INFORMATION CONTACT:

Regarding the guideline: Ruth Wolff, Center for Biologics Evaluation and Research (HFM–30), Food and Drug Administration, 1401 Rockville Pike, Rockville, MD 20852, 301–594–5660.

Regarding ICH: Janet J. Showalter, Office of Health Affairs (HFY–20), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301–827–0864.

SUPPLEMENTARY INFORMATION: In recent years, many important initiatives have been undertaken by regulatory authorities and industry associations to promote international harmonization of regulatory requirements. FDA has participated in many meetings designed to enhance harmonization and is committed to seeking scientifically based harmonized technical procedures for pharmaceutical development. One of the goals of harmonization is to identify and then reduce differences in technical requirements for drug development among regulatory agencies.

ICH was organized to provide an opportunity for tripartite harmonization initiatives to be developed with input from both regulatory and industry representatives. FDA also seeks input from consumer representatives and others. ICH is concerned with harmonization of technical requirements for the registration of pharmaceutical products among three regions: The European Union, Japan, and the United States. The six ICH sponsors are the European Commission, the European Federation of Pharmaceutical Industries Associations, the Japanese Ministry of Health and Welfare, the Japanese Pharmaceutical Manufacturers Association, the Centers for Drug Evaluation and Research and Biologics Evaluation and Research, FDA, and the Pharmaceutical Research and Manufacturers of America. The ICH Secretariat, which coordinates the preparation of documentation, is provided by the International Federation of Pharmaceutical Manufacturers Associations (IFPMA).

The ICH Steering Committee includes representatives from each of the ICH sponsors and the IFPMA, as well as observers from the World Health Organization, the Canadian Health Protection Branch, and the European Free Trade Area.

At a meeting held on November 29, 1995, the ICH Steering Committee agreed that a draft guideline entitled ''Viral Safety Evaluation of Biotechnology Products Derived From Cell Lines of Human or Animal Origin'' should be made available for public comment. The draft guideline is the product of the Quality Expert Working Group of the ICH. Comments about this draft will be considered by FDA and the Quality Expert Working Group. Ultimately, FDA intends to adopt the ICH Steering Committee's final guideline.

The draft guideline describes approaches for evaluating the risk of viral contamination and for removing viruses from biotechnology products derived from human or animal cell lines. The draft guideline emphasizes the value of many strategies including: (1) Thorough characterization/screening of the cell substrate starting material in order to identify which, if any, viral contaminants are present; (2) assessment of risk by a determination of the human tropism of the contaminants; (3) incorporation of studies that assess virus inactivation and removal steps in the production process; (4) careful design of viral clearance studies to avoid pitfalls and provide interpretable results; and (5) use of different methods of virus inactivation or removal in the same production process in order to achieve maximum viral clearance.

In the past, guidelines have generally been issued under § 10.90(b) (21 CFR 10.90(b)), which provides for the use of guidelines to state procedures or standards of general applicability that are not legal requirements but are acceptable to FDA. The agency is now in the process of revising § 10.90(b). Although this guideline does not create or confer any rights for or on any person and does not operate to bind FDA, it does represent the agency's current thinking on viral safety evaluation of biotechnology products.

Interested persons may, on or before August 8, 1996, submit to the Dockets Management Branch (address above) written comments on the draft guideline. Two copies of any comments are to be submitted, except that individuals may submit one copy. Comments are to be identified with the docket number found in brackets in the heading of this document. The draft guideline and received comments may be seen in the office above between 9 a.m. and 4 p.m., Monday through Friday.

The text of the draft guideline follows:

Viral Safety Evaluation of Biotechnology Products Derived From Cell Lines of Human or Animal Origin

I. Introduction

This document is concerned with testing and evaluation of the viral safety of biotechnology products derived from characterized cell lines of human or animal origin (i.e., mammalian, avian, insect), and outlines data that should be submitted in the marketing application/registration package. For the purposes of this document, the term virus excludes nonconventional transmissible agents like those associated with Bovine Spongiform Encephalopathy (BSE) and scrapie. Applicants are encouraged to discuss issues associated with BSE with the regulatory authorities.

The scope of the document covers products derived from cell cultures initiated from characterized cell banks. It covers products derived from in vitro cell culture, such as interferons, monoclonal antibodies, and recombinant deoxyribonucleic acid (DNA)-derived products including recombinant subunit vaccines, and also includes products

derived from hybridoma cells grown in vivo as ascites. In this latter case, special considerations apply and additional information on testing cells propagated in vivo is contained in Appendix 1. Inactivated vaccines, all live vaccines containing self-replicating agents, and genetically engineered live vectors are excluded from the scope of this document.

The risk of viral contamination is a feature common to all biotechnology products derived from cell lines. Such contamination could have serious clinical consequences and can arise from the contamination of the source cell lines themselves (cell substrates) or from adventitious introduction of virus during production. To date, however, biotechnology products derived from cell lines have not been implicated in the transmission of viruses. Nevertheless, it is expected that the safety of these products with regard to viral contamination can be reasonably assured only by the application of a virus testing program and assessment of virus removal and inactivation achieved by the manufacturing process, as outlined below.

Three principal, complementary approaches have evolved to control the potential viral contamination of biotechnology products:

(1) Selecting and testing cell lines and other raw materials, including media components, for the absence of undesirable viruses which may be infectious and/or pathogenic for humans;

(2) Assessing the capacity of the production processes to clear infectious viruses; and

(3) Testing the product at appropriate stages of production for the absence of contaminating infectious viruses.

All testing suffers from the inherent limitation of quantitative virus assays in that the ability to detect low viral concentrations depends for statistical reasons on the size of the sample. Therefore, no single approach will necessarily establish the safety of a product. Confidence that infectious virus is absent from the final product will in many instances not be derived solely from direct testing for their presence, but also from a demonstration that the purification regimen is capable of removing and/or inactivating the viruses.

The type and extent of viral tests and viral clearance studies required at different stages of production will depend on various factors and should be considered on a case-by-case and step-by-step basis. The factors that should be taken into account include the extent of cell bank characterization and qualification, the nature of any viruses detected, culture medium constituents, culture methods, facility and equipment design, the results of viral tests after cell culture, the ability of the process to clear viruses, and the type of product and its intended clinical use.

The purpose of this document is to provide a general framework for virus testing, experiments for the assessment of viral clearance, and a recommended approach for the design of viral tests and viral clearance studies. Related information is described in the appendices and selected definitions are provided in the Glossary.

Manufacturers should adjust the recommendations presented here to their specific product and its production process. The approach used by manufacturers in their overall strategy for ensuring viral safety should be explained and justified. In addition to the detailed data which is provided, an overall summary of the viral safety assessment would be useful in facilitating the review by regulatory authorities. This summary should contain a brief description of all aspects of the viral safety studies and strategies used to prevent virus contamination as they pertain to this document.

II. Potential Sources of Virus Contamination

Viral contamination of biotechnology products may arise from the original source of the cell lines or from adventitious introduction of virus during production processes.

A. Viruses That Could Occur in the Master Cell Bank (MCB)

Cells may have latent or persistent virus infection (e.g., herpesvirus) or endogenous retrovirus which may be transmitted vertically from one cell generation to the next, since the viral genome persists within the cell. Such viruses may be constitutively expressed or may unexpectedly become expressed as an infectious virus.

Viruses can be introduced into the MCB by several routes such as: (1) Derivation of cell lines from infected animals; (2) use of virus to establish the cell line; (3) use of contaminated biological reagents such as animal serum components; and (4) contamination during cell handling.

B. Adventitious Viruses That Could Be Introduced During Production

Adventitious viruses can be introduced into the final product by several routes including, but not limited to, the following: (1) Use of contaminated biological reagents such as animal serum components; (2) use of a virus for the induction of expression of specific genes encoding a desired protein; (3) use of a contaminated reagent, such as a monoclonal antibody affinity column; and (4) use of a contaminated excipient during formulation.

III. Cell Line Qualification: Testing for Viruses

An important part of qualifying a cell line for use in the production of a biotechnology product is the appropriate testing for the presence of virus.

A. Suggested Virus Tests for MCB, Working Cell Bank (WCB), and Cells at the Limit of In Vitro Cell Age Used for Production

Table 1 shows an example of virus tests to be performed once only at various cell levels, including MCB, WCB, and cells at the limit of in vitro cell age used for production.

1. Master Cell Bank

Extensive screening for both endogenous and nonendogenous viral contamination should be performed on the MCB. For heterohybrid cell lines in which one or more partners are human or nonhuman primate in origin, tests should be performed in order to detect viruses of human or nonhuman primate origin because viral contamination arising from these cells may pose a particular hazard.

Testing for nonendogenous viruses should include in vitro and in vivo inoculation tests and any other specific tests, including species-specific tests such as the mouse antibody production (MAP) test, that are appropriate, based on the passage history of the cell line, to detect possible contaminating viruses.

2. Working Cell Bank

Each WCB as a starting cell substrate for drug production should be tested for adventitious virus either by direct testing or by analysis of cells at the limit of in vitro cell age, initiated from the WCB. When appropriate nonendogenous virus tests have been performed on the MCB and cells cultured up to or beyond the limit of in vitro cell age have been derived from the WCB and used for testing for the presence of adventitious viruses, similar tests need not be performed on the initial WCB. Antibody production tests are usually not necessary for the WCB. An alternative approach in which full tests are carried out on the WCB rather than on the MCB would also be acceptable.

3. Cells at the Limit of In Vitro Cell Age Used for Production

The limit of in vitro cell age used for production should be based on data derived from production cells expanded under pilot-plant scale or commercial-scale conditions to the proposed in vitro cell age or beyond. Generally, the production cells are obtained by expansion of the WCB; the MCB could also be used to prepare the production cells. Cells at the limit of in vitro cell age should be evaluated once for those endogenous viruses that may have been undetected in the MCB and WCB. The performance of suitable tests (e.g., in vitro and in vivo) at least once on cells at the limit of in vitro cell age used for production would provide further assurance that the production process is not prone to contamination by adventitious virus. If any adventitious viruses are detected at this level, the process should be carefully checked in order to determine the cause of the contamination and completely redesigned if necessary.

B. Recommended Viral Detection and Identification Assays

Numerous assays can be used for the detection of endogenous and adventitious viruses. Table 2 outlines examples for these assays. They should be regarded as assay protocols recommended for the present, but the list is not all-inclusive or definitive. Since the most appropriate techniques may change with scientific progress, proposals for alternative techniques, when accompanied by adequate supporting data, may be acceptable. Manufacturers are encouraged to discuss these alternatives with the regulatory authorities. Other tests may be necessary depending on the individual case. Assays should include appropriate controls to ensure adequate sensitivity and specificity. Wherever a relatively high possibility of the presence of a specific virus can be predicted from the species of origin of the cell

substrate, specific tests and/or approaches may be necessary. If the cell line used for production is of human or nonhuman primate origin, additional tests for human viruses, such as those causing immunodeficiency diseases and hepatitis, should be performed unless otherwise justified. The polymerase chain reaction (PCR) may be appropriate for detection of sequences of these human viruses as well as for other specific viruses. The following is a brief description of a general framework and philosophical background within which the manufacturer should justify what was done.

1. Tests for Retroviruses

For the MCB and for cells cultured up to or beyond the limit of in vitro cell age used for production, tests for retroviruses, including infectivity assays in sensitive cell cultures and electron microscopy (EM) studies, should be carried out. If infectivity is not detected and no retrovirus or retrovirus-like particles have been observed by EM, reverse transcriptase (RT) or other appropriate assays should be performed to detect retroviruses which may be noninfectious. Induction studies have not been found to be useful.

2. In Vitro Assays

In vitro tests are carried out by the inoculation of a test article (see Table 2) into various susceptible indicator cell cultures capable of detecting a wide range of human and relevant animal viruses. The choice of cells used in the test is governed by the species of origin of the cell bank to be tested, but should include a human and/or a nonhuman primate cell line susceptible to human viruses. The nature of the assay and the sample to be tested are governed by the type of virus which may possibly be present based on the origin or handling of the cells. Both cytopathic and hemadsorbing viruses should be sought.

3. In Vivo Assays

A test article (see Table 2) should be inoculated into animals, including suckling and adult mice, and in embryonated eggs to reveal viruses that cannot grow in cell cultures. Additional animal species may be used depending on the nature and source of the cell lines being tested. The health of the animals should be monitored and any abnormality should be investigated to establish the cause of the illness.

4. Antibody Production Tests

Species-specific viruses present in rodent cell lines may be detected by inoculating test article (see Table 2) into virus-free animals and examining the serum antibody level or enzyme activity after a specified period. Examples of such tests are the MAP test, rat antibody production (RAP) test, and hamster antibody production (HAP) test. The viruses currently screened for in the antibody production assays are discussed in Table 3.

C. Acceptability of Cell Lines

It is recognized that some cell lines used for the manufacture of product will contain endogenous retroviruses, other viruses, or viral sequences. In such circumstances, the action plan recommended for manufacture is described in section V. of this document. The acceptability of cell lines containing viruses other than endogenous retroviruses will be considered on an individual basis by the regulatory authorities, by taking into account a risk/benefit analysis based on the benefit of the product and its intended clinical use, the nature of the contaminating viruses, their potential for infecting humans or for causing disease in humans, the purification process for the product (e.g., viral clearance evaluation data), and the extent of the virus tests conducted on the purified bulk.

IV. Testing for Viruses in Unprocessed Bulk

The unprocessed bulk constitutes one or multiple pooled harvests of cells and culture media. When cells are not readily accessible (e.g., hollow fiber or similar systems), the unprocessed bulk would constitute fluids harvested from the fermenter. A representative sample of the unprocessed bulk, removed from the production reactor prior to further processing, represents one of the most suitable levels at which the possibility of adventitious virus contamination can be determined with a high probability of detection. Appropriate testing for viruses should be performed at the unprocessed bulk level unless virus testing is made more sensitive by initial partial processing (e.g., unprocessed bulk may be toxic in test cell cultures, whereas partially processed bulk may not be toxic).

In certain instances it may be more appropriate to test a mixture consisting of both intact and disrupted cells and their cell culture supernatants removed from the production reactor prior to further processing. Data from at least 3 lots of unprocessed bulk at pilot-plant scale or commercial scale should be submitted as part of the registration/marketing application package.

It is recommended that manufacturers develop programs for the ongoing assessment of adventitious viruses in production batches. The scope, extent, and frequency of virus testing on the unprocessed bulk should be determined by taking several points into consideration including the nature of the cell lines used to produce the desired products, the results and extent of virus tests performed during the qualification of the cell lines, the cultivation method, raw material sources, and results of viral clearance studies. In vitro screening tests, using one or several cell lines, are generally employed to test unprocessed bulk. If appropriate, a PCR test or other suitable methods may be used.

Generally, harvest material in which adventitious virus has been detected should not be used to manufacture the product. If any adventitious viruses are detected at this level, the process should be carefully checked to determine the cause of the contamination, and appropriate actions taken.

V. Rationale and Action Plan for Viral Clearance Studies and Virus Tests on Purified Bulk

It is important to design the most relevant and rational protocol for virus tests from the MCB level through the various stages of drug production to the final product, including evaluation and characterization of viral clearance from unprocessed bulk. The evaluation and characterization of viral clearance plays a critical role in this scheme. The goal should be to obtain the best reasonable assurance that the product is free of virus contamination.

In selecting viruses to use for a clearance study, it is useful to distinguish between the need to evaluate processes for their ability to clear viruses that are known to be present and the desire to estimate the robustness of the process by characterizing the clearance of nonspecific ''model'' viruses (described later). Definitions of ''relevant'', specific and nonspecific ''model'' viruses are given in the Glossary. Process evaluation requires knowledge of how much virus may be present in the process, such as the unprocessed bulk, and how much can be cleared in order to assess product safety. Knowledge of the time dependence for inactivation procedures is helpful in assuring the effectiveness of the inactivation process.

When a manufacturing process is characterized for robustness of clearance using nonspecific ''model'' viruses, less extensive virus removal/inactivation studies are appropriate. Indepth, time-dependent inactivation studies, demonstration of reproducibility of inactivation/removal, and evaluation of process parameters are not required. These studies should be performed on the manufacturing process in Cases A through E as described below.

Table 4 presents an example of an action plan in terms of process evaluation and characterization of viral clearance as well as virus tests on purified bulk, in response to the results of virus tests on cells and/or the unprocessed bulk. Various cases are considered. In all cases, characterization of clearance using nonspecific ''model'' viruses should be performed. The most common situations are Cases A and B. Production systems contaminated with a virus other than a rodent retrovirus are normally not used. Where there are convincing and well justified reasons for drug production using a cell line from Cases C, D, or E, these should be discussed with the regulatory authorities. With Cases C, D, and E, it is important to have validated effective steps to inactivate/remove the virus in question from the manufacturing process.

Case A: Where no virus, virus-like particle, or retrovirus-like particle has been demonstrated in the cells or the unprocessed bulk, virus removal and inactivation studies should be performed with nonspecific ''model'' viruses as previously stated.

Case B: Where only a rodent retrovirus (or a retrovirus-like particle which is believed to be nonpathogenic, such as rodent A- and R-type particles) is present, process evaluation using a specific ''model'' virus, such as a murine leukemia virus, should be performed. Purified bulk should be tested using suitable methods having high specificity and sensitivity for the detection of the virus in question. For marketing authorization, data from at least 3 lots of purified bulk at pilot-plant scale or commercial scale should be provided. Cell lines such as Chinese hamster ovary (CHO), C127, baby hamster kidney (BHK), and murine hybridoma cell lines have frequently been used as substrates for drug

production with no reported safety problems related to viral contamination of the products. For these cell lines in which the endogenous particles have been extensively characterized and clearance has been demonstrated, it is not usually necessary to assay for the presence of the noninfectious particles in purified bulk.

Case C: When the cells or unprocessed bulk are known to contain a virus, other than a rodent retrovirus, for which there is no evidence of capacity for infecting humans, (such as those identified by footnote 2 in Table 3, except rodent retroviruses (Case B)), virus removal and inactivation evaluation studies should use the identified virus. If it is not possible to use the identified virus, ''relevant'' or specific ''model'' viruses should be used to demonstrate acceptable clearance. Time-dependent inactivation for identified (or ''relevant'' or specific ''model'') viruses at the critical inactivation step(s) should be obtained as part of process evaluation for these viruses. Purified bulk should be tested using suitable methods having high specificity and sensitivity for the detection of the virus in question. For the purpose of marketing authorization, data from at least 3 lots of purified bulk manufactured at pilot-plant scale or commercial scale should be provided.

Case D: Where a known human pathogen, such as those indicated by footnote 1 in Table 3, is identified, the product may be acceptable only under exceptional circumstances. In this instance, it is recommended that the identified virus be used for virus removal and inactivation evaluation studies and specific methods with high specificity and sensitivity for the detection of the virus in question be employed. If it is not possible to use the identified virus, ''relevant'' and/or specific ''model'' viruses (described later) should be used. The process should be shown to achieve the removal and inactivation of the selected viruses during the purification and inactivation processes. Time-dependent inactivation data for the critical inactivation step(s) should be obtained as part of process evaluation. Purified bulk should be tested using suitable methods having high specificity and sensitivity for the detection of the virus in question. For the purpose of marketing authorization, data from at least 3 lots of purified bulk manufactured at pilot-plant scale or commercial scale should be provided.

Case E: When a virus which cannot be classified by currently available methodologies is detected in the cells or unprocessed bulk, the product is usually considered unacceptable since the virus may prove to be pathogenic. In the very rare case where there are convincing and well justified reasons for drug production using such a cell line, this should be discussed with the regulatory authorities before proceeding further.

VI. Evaluation and Characterization of Viral Clearance Procedures

Evaluation and characterization of the virus removal and/or inactivation procedures plays an important role in establishing the safety of biotechnology products. Many instances of contamination in the past have occurred with agents whose presence was not known or even suspected, and though this happened to biological products derived from various source materials other than fully characterized cell lines, assessment of viral clearance will provide a measure of confidence that any unknown, unsuspected, and harmful viruses may be removed.

The objective of viral clearance studies is to assess process step(s) that can be considered to be effective in inactivating/removing viruses and to estimate quantitatively the overall level of virus reduction obtained by the process. This should be achieved by the deliberate addition (''spiking'') of significant amounts of a virus to the crude material and/or to different fractions obtained during the various process stages and demonstrating its removal or inactivation during the subsequent stages. It is not necessary to evaluate or characterize every stage of a manufacturing process if adequate clearance is demonstrated by the use of fewer steps.

The reduction of virus infectivity may be achieved by removal of virus particles or by inactivation of viral infectivity. For each production stage assessed, the possible mechanism of loss of viral infectivity should be described with regard to whether it is due to inactivation or removal. For inactivation steps, the study should be planned in such a way that samples are taken at different times and an inactivation curve constructed. Studies should be carried out in a manner that is well documented and controlled (see section VI.B.5).

Viral clearance evaluation studies are performed to demonstrate the clearance of a virus known to be present in the MCB and/or to provide some level of assurance that adventitious viruses which could not be detected, or might gain access to the production process, would be cleared.

In contrast to viral clearance studies described above for viruses known to be present, studies to characterize the ability to remove and/or inactivate other viruses should be conducted. The purpose of the studies with viruses that are not known or expected to be present is to characterize the robustness of the procedure rather than to achieve a specific inactivation or removal goal. They are not performed to evaluate a specific safety risk. Therefore, a specific clearance value need not be achieved.

A. The Choice of Viruses for the Evaluation and Characterization of Viral Clearance

Viruses for clearance evaluation and process characterization studies should be chosen to resemble viruses which may contaminate the product and to represent a wide range of physico-chemical properties in order to test the ability of the system to eliminate viruses in general. The manufacturer should justify the choice of viruses in accordance with the aims of the evaluation and characterization study and the guidance provided in this guideline.

1. ''Relevant'' Viruses and ''Model'' Viruses

A major issue in performing a viral clearance study is to determine which viruses should be used. Such viruses fall into three categories: ''Relevant'' viruses, specific ''model'' viruses, and nonspecific ''model'' viruses.

''Relevant'' viruses are viruses used in process evaluation of viral clearance studies which are either the identified viruses, or of the same species as the viruses that are known, or likely to contaminate the cell substrate or any other reagents or materials used in the production process. The purification and/or inactivation process should demonstrate the capability to remove and/or inactivate such viruses. When a ''relevant'' virus is not available or when it is not well adapted to process evaluation of viral clearance studies (e.g., it cannot be grown in vitro to sufficiently high titers), a specific ''model'' virus should be used as a substitute. An appropriate specific ''model'' virus may be a virus which is closely related to the known or suspected virus (same genus or family), having similar physical and chemical properties to the observed or suspected virus.

Cell lines derived from rodents usually contain endogenous retrovirus particles or retrovirus-like particles, which may be infectious (C-type particles) or noninfectious (cytoplasmic A- and R-type particles). The capacity of the manufacturing process to remove and/or inactivate rodent retroviruses from products obtained from such cells should be determined. This may be accomplished by using a murine leukemia virus, a specific ''model'' virus in the case of cells of murine origin. When human cell lines secreting monoclonal antibodies have been obtained by the immortalization of B lymphocytes by Epstein-Barr Virus (EBV), the ability of the manufacturing process to remove and/or inactivate a herpes virus should be determined. Pseudorabies virus may also be used as a specific ''model'' virus.

When the purpose is to characterize the capacity of the manufacturing process to remove and/or inactivate viruses in general, i.e., to characterize the robustness of the clearance process, viral clearance characterization studies should be performed with nonspecific ''model'' viruses with differing properties. Data obtained from studies with ''relevant'' and/or specific ''model'' viruses may also contribute to this assessment. It is not necessary to test all types of viruses. Preference should be given to viruses that display a significant resistance to physical and/or chemical treatments. The results obtained for such viruses provide useful information about the ability of the production process to remove and/or inactivate viruses in general. The choice and number of viruses used will be influenced by the quality and characterization of the cell lines and the production process.

Examples of useful ''model'' viruses representing a range of physico-chemical structures and examples of viruses which have been used in viral clearance studies are given in Appendix 2 and Table A–1.

2. Other Considerations

Additional points to be considered are as follows:

(a) Viruses which can be grown to high titer are desirable, although this may not always be possible.

(b) There should be an efficient and reliable assay for the detection of each virus

used, for every stage of manufacturing that is tested.

(c) Consideration should be given to the health hazard which certain viruses may pose to the personnel performing the clearance studies.

B. Design and Implications of Viral Clearance Evaluation and Characterization Studies

1. Facility and Staff

It is inappropriate to introduce any virus into a production facility because of good manufacturing practice (GMP) constraints. Therefore, viral clearance studies should be conducted in a separate laboratory equipped for virological work and performed by staff with virological expertise in conjunction with production personnel involved in designing and preparing a scaled-down version of the purification process.

2. Scaled-down Production System

The validity of the scaling-down should be demonstrated. The level of purification of the scaled-down version should represent as closely as possible the production procedure. For chromatographic equipment, column bed-height, linear flow-rate, flow-rate-to-bed-volume ratio (i.e., contact time), buffer and gel types, pH, temperature, and concentration of protein, salt, and product should all be shown to be representative of commercial-scale manufacturing. For other procedures, similar considerations apply. Deviations which cannot be avoided should be discussed with regard to their influence on the results.

3. Analysis of Step-wise Elimination of Virus

When viral clearance studies are being performed, it is desirable to assess the contribution of more than one production step to virus elimination. Essential stages of the purification process should be individually assessed for their ability to remove and inactivate virus and careful consideration should be given to the exact definition of an individual stage. Sufficient virus should be present in the material of each stage to be tested so that an adequate assessment of the effectiveness of each step is obtained. Generally, virus should be added to in-process material of each stage to be tested. In some cases, simply adding high titer virus to unpurified bulk and testing its concentration between steps will be sufficient. When virucidal buffers are used in multiple steps within the manufacturing process, alternative strategies such as parallel spiking in less virucidal buffers may be carried out as part of the overall process assessment. The virus titer before and after each step being tested should be determined. Quantitative infectivity assays should have adequate sensitivity and reproducibility and should be performed with sufficient replicates to ensure adequate statistical validity of the result (see Appendix 3). Quantitative assays not associated with infectivity may be used if justified. Appropriate virus controls should be included in all infectivity assays to ensure the sensitivity of the method. Also, the statistics of sampling virus when at low concentrations should be considered (Appendix 4).

4. Determining Physical Removal Versus Inactivation

Reduction in virus infectivity may be achieved by the removal or inactivation of virus. For each production stage assessed, the possible mechanism of loss of viral infectivity should be described with regard to whether it is due to inactivation or removal. If little clearance of infectivity is achieved by the production process, and the clearance of virus is considered to be a major factor in the safety of the product, specific or additional inactivation/removal steps should be introduced. It may be necessary to distinguish between removal and inactivation for a particular step, e.g., when there is a possibility that a buffer used in more than one clearance step may contribute to inactivation during each step, i.e., the contribution to inactivation by a buffer shared by several chromatographic steps and the removal achieved by each of these chromatographic steps should be distinguished. Assurance should be provided that any virus potentially retained by the production system would be adequately destroyed or removed prior to reuse of the system. For example, such evidence may be provided by demonstrating that the cleaning and regeneration procedures do inactivate or remove virus.

5. Inactivation Assessment

For assessment of viral inactivation, unprocessed crude material or intermediate material should be spiked with infectious virus and the reduction factor calculated. The determination of initial virus load for assessing inactivation potential may be derived from the titer of the spiking virus preparation. This may be of importance when virucidal buffers are used in multiple steps within the manufacturing process. Virus inactivation is not a simple, first order reaction and is usually more complex, with a fast ''phase 1'' and a slow ''phase 2.'' The study should, therefore, be planned in such a way that samples are taken at different times and an inactivation curve constructed. It is recommended that studies for inactivation include at least one time point less than the minimum exposure time and greater than zero, in addition to the minimum exposure time. These types of data are particularly important where the virus is a ''relevant'' virus known to be a human pathogen and an effective inactivation process is being designed.

6. Function and Regeneration of Columns

Over time and after repeated use, the ability of chromatography columns and other devices used in the purification scheme to clear virus may vary. Some estimate of the stability of the viral clearance after several uses may provide support for repeated use of such columns. Assurance should be provided that any virus potentially retained by the production system would be adequately destroyed or removed prior to reuse of the system. For example, such evidence may be provided by demonstrating that the cleaning and regeneration procedures do inactivate or remove virus.

7. Specific Precautions

(a) Care should be taken in preparing the high-titer virus to avoid aggregation which may enhance physical removal and decrease inactivation, thus distorting the correlation with actual production.

(b) Consideration should be given to the minimum quantity of virus which can be reliably assayed.

(c) The study should include parallel control assays to assess the loss of infectivity of the virus due to such reasons as the dilution, concentration, filtration, or storage of samples before titration.

(d) The virus ''spike'' should be added to the product in a small volume so as not to dilute or change the characteristics of the product. Diluted, test-protein sample is no longer identical to the product obtained at commercial scale.

(e) Small differences in, for example, buffers, media, or reagents, can substantially affect viral clearance.

(f) Virus inactivation is time-dependent, therefore, the amount of time a spiked product remains in a particular buffer solution or on a particular chromatography column should reflect the conditions of the commercial-scale process.

(g) Buffers and product should be evaluated independently for toxicity or interference in assays used to determine the virus titer, as these components may adversely affect the indicator cells. If the solutions are toxic to the indicator cells, dilution, adjustment of the pH, or dialysis of the buffer containing spiked virus may be necessary. If the product itself has antiviral activity, the clearance study may need to be performed without the product in a ''mock'' run, although omitting the product or substituting a similar protein that does not have antiviral activity could affect the behavior of the virus in some production steps. Sufficient controls to demonstrate the effect of procedures used solely to prepare the sample for assay (e.g., dialysis, storage) on the removal/inactivation of the spiking virus should be included.

(h) Many purification schemes use the same or similar buffers or columns repetitively. The effects of this approach should be taken into account when analyzing the data. The effectiveness of virus elimination by a particular process may vary with the manufacturing stage at which it is used.

(i) Overall reduction factors may be underestimated where production conditions or buffers are too cytotoxic or virucidal and should be discussed on a case-by-case basis.

C. Interpretation of Viral Clearance Studies; Acceptability

The objective of assessing virus inactivation/removal is to evaluate and characterize process steps that can be considered to be effective in inactivating/removing viruses and to estimate quantitatively the overall level of virus reduction obtained by the manufacturing process. For virus contaminants, as in Cases B through E, it is important to show that not only is the virus eliminated or inactivated, but that there is excess capacity for viral clearance built into the purification process to assure an appropriate level of safety for the final product. The amount of virus eliminated or inactivated by the production

process should be compared to the amount of virus which may be present in unprocessed bulk. However, for inactivation studies in which nonspecific ''model'' viruses are used, or when specific ''model'' viruses are used as surrogates for virus particles such as the CHO intracytoplasmic retrovirus-like particles, it is sufficient to demonstrate reproducible clearance in at least two independent experiments. It is recommended that these studies for inactivation include at least one time-point less than the minimum exposure time and greater than zero, in addition to the minimum exposure time.

To carry out this comparison, it is important to estimate the amount of virus in the unprocessed bulk. This estimate should be obtained using assays for infectivity or other methods such as transmission electron microscopy (TEM). The entire purification process should be able to eliminate substantially more virus than is estimated to be present in a single-dose-equivalent of unprocessed bulk. See Appendix 5 for calculation of virus reduction factors and Appendix 6 for calculation of estimated particles per dose.

A combination of factors must be considered when judging the data supporting the effectiveness of virus inactivation/removal procedures. These include:

(i) The appropriateness of the test viruses used;

(ii) The design of the clearance studies;

(iii) The log reduction achieved;

(iv) The time dependence of inactivation;

(v) The potential effects of variation in process parameters on virus inactivation/removal; and

(vi) The limits of assay sensitivities.

Effective clearance may be achieved by any of the following: Multiple inactivation steps, multiple complementary separation steps, or combinations of inactivation and separation steps. Since separation methods may be dependent on the extremely specific physico-chemical properties of a virus which influence its interaction with gel matrices and precipitation properties, ''model'' viruses may be separated in a different manner than a target virus. Differences may originate from changes in surface properties such as glycosylation. However, despite these potential variables, effective removal can be obtained by a combination of complementary separation steps or combinations of inactivation and separation steps. Therefore, well-designed separation steps, such as chromatographic procedures, filtration steps, and extractions, can be effective virus removal steps provided that they are performed under appropriately controlled conditions.

An overall reduction factor is generally expressed as the sum of the individual factors. However, reduction in virus titer of the order of 1 $\log_{10}$ or less would be considered negligible and would be ignored unless assay variability were shown to be below that order of magnitude.

If little reduction of infectivity is achieved by the production process, and the removal of virus is considered to be a major factor in the safety of the product, a specific, additional inactivation/removal step or steps should be introduced. For all viruses, manufacturers should justify the acceptability of the reduction factors obtained. Results will be evaluated on the basis of the factors listed above.

D. Limitations of Viral Clearance Studies

Viral clearance studies are useful for contributing to the assurance that an acceptable level of safety in the final product is achieved, but do not by themselves establish safety. However, a number of factors in the design and execution of viral clearance studies may lead to an incorrect estimate of the ability of the process to remove virus infectivity (see Appendices 2, 3, and 4). These factors include the following:

1. Virus preparations used in clearance studies for a production process are likely to be produced in tissue culture. The behavior of a tissue culture virus in a production step may be different from that of the native virus, for example, if native and cultured viruses differ in purity or degree of aggregation.

2. Inactivation of virus infectivity frequently follows a biphasic curve in which a rapid initial phase is followed by a slower phase. It is possible that virus escaping a first inactivation step may be more resistant to subsequent steps. For example, if the resistant fraction takes the form of virus aggregates, infectivity may be resistant to a range of different chemical treatments and to heating.

3. The ability of the overall process to remove infectivity is expressed as the sum of the logarithm of the reductions at each step. The summation of the reduction factors of multiple steps, particularly of steps with little reduction (e.g., below 1 $\log_{10}$), may overestimate the true potential for virus elimination. Furthermore, reduction values achieved by repetition of identical or near identical procedures should not be included unless justified.

4. The expression of reduction factors as logarithmic reductions in titer implies that, while residual virus infectivity may be greatly reduced, it will never be reduced to zero. For example, a reduction in the infectivity of a preparation containing 8 $\log_{10}$ infectious units per milliliter (mL) by a factor of 8 $\log_{10}$ leaves zero $\log_{10}$ per mL or one infectious unit per mL, taking into consideration the limit of detection of the assay.

5. Pilot-plant scale processing may differ from commercial-scale processing despite care taken to design the scaled-down process.

6. Addition of individual virus reduction factors resulting from similar inactivation mechanisms along the manufacturing process may overestimate overall viral clearance.

E. Statistics

The viral clearance studies should include the use of statistical analysis of the data to evaluate the results. The study results should be statistically valid to support the conclusions reached (see Appendices 3 and 4).

F. Re-Evaluation of Viral Clearance

Whenever significant changes in the production or purification process are made, the effect of that change on viral clearance should be considered and the system re-evaluated as needed. For example, changes in production processes may cause significant changes in the amount of virus produced by the cell line; changes in process steps may change the extent of viral clearance.

VII. Summary

This document suggests approaches for the evaluation of the risk of viral contamination and for the removal of virus from the product, thus contributing to the production of safe biotechnology products derived from animal or human cell lines, and emphasizes the value of many strategies, including:

A. Thorough characterization/screening of cell substrate starting material in order to identify which, if any, viral contaminants are present;

B. Assessment of risk by determination of the human tropism of the contaminants;

C. Incorporation of studies which assess virus inactivation and removal steps into the production process;

D. Careful design of the viral clearance studies to avoid pitfalls and provide interpretable results; and

E. Use of different methods of virus inactivation or removal in the same production process in order to achieve maximum viral clearance.

Glossary

Adventitious Virus. See virus.

Cell Substrate. Cells used to manufacture product.

Endogenous Virus. See virus.

Inactivation. Reduction of virus infectivity caused by chemical or physical modification.

In Vitro Cell Age. A measure of the period between thawing of the MCB vial(s) and harvest of the production vessel measured by elapsed chronological time in culture, population doubling level of the cells, or passage level of the cells when subcultivated by a defined procedure for dilution of the culture.

Master Cell Bank (MCB). An aliquot of a single pool of cells which generally has been prepared from the selected cell clone under defined conditions, dispensed into multiple containers, and stored under defined conditions. The MCB is used to derive all working cell banks. The testing performed on a new MCB (from a previous initial cell clone, MCB, or WCB) should be the same as for the MCB, unless justified.

Minimum Exposure Time. The shortest period for which a treatment step will be maintained.

Nonendogenous Virus. See virus.

Process Characterization of Viral Clearance. Viral clearance studies in which nonspecific ''model'' viruses are used to assess the robustness of the manufacturing process to remove and/or inactivate viruses.

Process Evaluation Studies of Viral Clearance. Viral clearance studies in which ''relevant'' and/or specific ''model'' viruses are used to determine the ability of the manufacturing process to remove and/or inactivate these viruses.

Production Cells. Cell substrate used to manufacture product.

Unprocessed Bulk. One or multiple pooled harvests of cells and culture media. When

cells are not readily accessible, the unprocessed bulk would constitute fluid harvested from the fermenter.

Virus. Intracellularly replicating infectious agents that are potentially pathogenic, possessing only a single type of nucleic acid (either ribonucleic acid (RNA) or DNA), are unable to grow and undergo binary fission, and multiply in the form of their genetic material.

Adventitious Virus. Unintentionally introduced contaminant viruses.

Endogenous Virus. Viral entity whose genome is part of the germ line of the species of origin of the cell line and is covalently integrated into the genome of animal from which the parental cell line was derived. For the purposes of this document, intentionally introduced, nonintegrated viruses such as EBV used to immortalize cell substrates or Bovine Papilloma Virus fit in this category.

Nonendogenous Virus. Viruses from external sources present in the Master Cell Bank.

Nonspecific Model Virus. A virus used for characterization of viral clearance of the process when the purpose is to characterize the capacity of the manufacturing process to remove and/or inactivate viruses in general, i.e., to characterize the robustness of the purification process.

Relevant Virus. Virus used in process evaluation studies which is either the identified virus, or of the same species as the virus that is known, or likely to contaminate the cell substrate or any other reagents or materials used in the production process.

Specific Model Virus. Virus which is closely related to the known or suspected virus (same genus or family), having similar physical and chemical properties to those of the observed or suspected virus.

Viral Clearance. Elimination of target virus by removal of viral particles or inactivation of viral infectivity.

Virus-like Particles. Structures visible by electron microscopy which morphologically appear to be related to known viruses.

Virus Removal. Physical separation of virus particles from the intended product.

Working Cell Bank (WCB). The WCB is prepared from aliquots of a homogeneous suspension of cells obtained from culturing the MCB under defined culture conditions.

TABLE 1.—VIRUS TESTS TO BE PERFORMED ONCE AT VARIOUS CELL LEVELS

	MCB	WCB[1]	Cells at the limit[2]
Tests for Retroviruses and Other Endogenous Viruses			
Infectivity	+	–	+
Electron microscopy[3]	+[3]	–	+[3]
Reverse transcriptase[4]	+[4]	–	+[4]
Other virus-specific tests[5]	as appropriate[5]	–	as appropriate[5]
Tests for Nonendogenous or Adventitious Viruses			
In vitro Assays	+	–[6]	+
In vivo Assays	+	–[6]	+
Antibody production tests[7]	+[7]	–	–
Other virus-specific tests[8]	+[8]	–	–

[1] See text—section III.A.2.
[2] Cells at the limit; cells at the limit of in vitro cell age used for production (See text—section III.A.3.)
[3] May also detect other agents.
[4] Not necessary if positive by retrovirus infectivity test.
[5] As appropriate for cell lines which are known to have been infected by such agents.
[6] For the first WCB, this test should be performed on cells at the limit of in vitro cell age, generated from that WCB; for WCB's subsequent to the first WCB, a single in vitro and in vivo test can be done either directly on the WCB or on cells at the limit of in vitro cell age.
[7] e.g., MAP, RAP, HAP—usually applicable for rodent cell lines.
[8] e.g, tests for cell lines derived from human, nonhuman primate, or other cell lines as appropriate.

TABLE 2.—EXAMPLES OF THE USE AND LIMITATIONS OF ASSAYS WHICH MAY BE USED TO TEST FOR VIRUS

Test	Test article	Detection capability	Detection limitation
Anbibody production	Lysate of cells and their culture medium	Specific viral antigens	Agents not infectious for animal test system.
in vivo virus screen	Lysate of cells and their culture medium	Broad range of viruses pathogenic for humans	Agents failing to replicate or produce diseases in the test system.
in vitro virus screen for		Broad range of viruses pathogenic for humans	Agents failing to replicate or produce diseases in the test system.
1. Cell bank characterization	1. Lysate of cells and their culture medium (for cocultivation, intact cells should be in the test article)		
2. Production screen	2. Unprocessed bulk harvest or lysate of cells and their cell culture medium from the production reactor		
TEM on:		Virus and virus-like particles	Qualitative assay with assessment of identity.
1. Cell substrate	1. Viable cells		
2. Cell culture supernatant	2. Concentrated cell-free supernatant		

TABLE 2.—EXAMPLES OF THE USE AND LIMITATIONS OF ASSAYS WHICH MAY BE USED TO TEST FOR VIRUS—Continued

Test	Test article	Detection capability	Detection limitation
Reverse transcriptase (RT)	Cell-free culture supernatant	Retroviruses and expressed retroviral RT	Only detects enzymes with optimal activity under preferred conditions. Interpretation may be difficult due to presence of cellular enzymes; background with some concentrated samples.
Retrovirus (RV) infectivity	Cell-free culture supernatant	Infectious retroviruses	RV failing to replicate or form discrete foci or plaques in the chosen test system.
Cocultivation infectivity endpoint	Viable cells	Infectious retroviruses	RV failing to replicate. See above under RV infectivity.
TEM endpoint			See above under TEM.[1]
RT endpoint			See above under RT.
PCR (Polymerase chain reaction)	Cells, culture fluid and other materials	Specific virus sequences	Primer sequences must be present. Does not indicate whether virus is infectious.

[1] In addition, difficult to distinguish test article from indicator cells.

TABLE 3.—VIRUS DETECTED IN ANTIBODY PRODUCTION TESTS

MAP	HAP	RAP
Ectromelia Virus[2,3]	Lymphocytic ChoriomeningitisVirus (LCM)[1,3]	Hantaan Virus[1,3]
Hantaan Virus[1,3]	Pneumonia Virus of Mice (PVM)[2,3]	Kilham Rat Virus (KRV)[2,3]
K Virus[2]	Reovirus Type 3 (Reo3)[1,3]	Mouse Encephalomyelitis Virus (Theiler's, GDVII)[2]
Lactic Dehydrogenase Virus (LDH)[2]	Sendai Virus[1,3]	Pneumonia Virus of Mice (PVM)[2,3]
Lymmphocytic Choriomeningitis Virus (LCM)[1,3]	SV5	Rat Coronavirus (RCV)[2]
Minute Virus of Mice (MVM)[2,3]		Reovirus Type 3 (Reo3)[1,3]
Mouse Adenovirus (MAV)[2,3]		Sendai Virus[1,3]
Mouse Cytomegalovirus (MCMV)[2,3]		Sialoacryoadenitis Virus (SDAV)[2]
Mouse Encephalomyelitis Virus (Theiler's, GDVII)[2]		Toolan Virus (HI)[2,3]
Mouse Hepatitis Virus (MHV)[2]		
Mouse Rotavirus (EDIM)[2,3]		
Pneumonia Virus of Mice (PVM)[2,3]		
Polyoma Virus[2]		
Reovirus Type 3 (Reo3)[1,3]		
Sendai Virus[1,3]		
Thymic Virus[2]		

[1] Viruses for which there is evidence of capacity for infecting humans or primates.
[2] Viruses for which there is no evidence of capacity for infecting humans.
[3] Virus capable of replicating in vitro in cells of human or primate origin.

TABLE 4.—ACTION PLAN FOR PROCESS ASSESSMENT OF VIRAL CLEARANCE AND VIRUS TESTS ON PURIFIED BULK

	Case A	Case B	Case C[2]	Case D[2]	Case E[2]
Status					
Presence of virus[1]	–	–	+	+	(+)[3]
Virus-like particles[1]	–	–	–	–	(+)[3]
Retrovirus-like particles[1]	–	+	–	–	(+)[3]
Virus identified	not applicable	+	+	+	–
Virus pathogenic for humans	not applicable	–[4]	–[4]	+	unknown
Action					
Process characterization of viral clearance using nonspecific ''model'' viruses	yes[5]	yes[5]	yes[5]	yes[5]	yes[7]
Process evaluation of viral clearance using ''relevant'' or specific ''model'' viruses	no	yes[6]	yes[6]	yes[6]	yes[7]
Test for virus in purified bulk	not applicable	yes[8]	yes[8]	yes[8]	yes[8]

[1] Results of virus tests for the cell substrate and/or at the unprocessed bulk level. Cell cultures used for production which are contaminated with viruses will generally not be acceptable. Endogenous viruses (such as retroviruses) or viruses that are an integral part of the MCB may be acceptable if appropriate viral clearance evaluation procesures are followed.
[2] The use of source material which is contaminated with viruses, whether or not they are known to be infectious and/or pathogenic in humans, will only be permitted under very exceptional circumstances.

[3] Virus has been observed by either direct or indirect methods.
[4] Believed to be nonpathogenic.
[5] Characterization of clearance using nonspecific ''model'' viruses should be performed.
[6] Process evaluation for ''relevant'' viruses or specific ''model'' viruses should be performed.
[7] See text under Case E.
[8] The absence of detectible virus should be confirmed for purified bulk by means of suitable methods having high specificity and sensitivity for the detection of the virus in question. For the purpose of marketing authorization, data from at least 3 lots of purified bulk manufactured at pilot-plant scale or commercial scale should be provided. However, for cell lines such as CHO cells for which the endogenous particles have been extensively characterized and adequate clearance has been demonstrated, it is not usually necessary to assay for the presence of the noninfectious particles in purified bulk.

Appendix 1

Products Derived From Characterized Cell Banks Which Were Subsequently Grown In Vivo

For products manufactured from fluids harvested from animals inoculated with cells from characterized banks, additional information regarding the animals should be provided.

Whenever possible, animals used in the manufacture of biotechnological/biological products should be obtained from well defined, specific pathogen-free colonies. Quarantine procedures for newly arrived as well as diseased animals should be described, and assurance provided that all containment, cleaning, and decontamination methodologies employed within the facility are adequate to contain the spread of adventitious agents. This may be accomplished through the use of a sentinel program. A listing of agents for which testing is performed should also be included. Veterinary support services should be available on-site or within easy access. The degree to which the vivarium is segregated from other areas of the manufacturing facility should be described. Personnel practices should be adequate to ensure safety.

Procedures for the maintenance of the animals should be fully described. These would include diet, cleaning, and feeding schedules, provisions for periodic veterinary care if applicable, and details of special handling that the animals may require once inoculated. A description of the priming regimen(s) for the animals, the preparation of the inoculum, and the site and route of inoculation should also be included.

The primary harvest material from animals may be considered an equivalent stage of manufacture to unprocessed bulk harvest from a bioreactor. Therefore, all testing considerations previously outlined in section IV. of this document should apply. In addition, the manufacturer should assess the bioburden of the unprocessed bulk, determine whether the material is free of mycoplasma, and perform species-specific assay(s) as well as in vivo testing in adult and suckling mice.

Appendix 2

The Choice of Viruses for Viral Clearance Studies

A. Examples of Useful ''Model'' Viruses:

1. Nonspecific ''model'' viruses representing a range of physico-chemical structures:

- SV40 (Polyomavirus maccacae 1), human polio virus 1 (Sabin), animal parvovirus or some other small, nonenveloped viruses;
- a parainfluenza virus or influenza virus, Sindbis virus or some other medium-to-large, enveloped, RNA viruses;
- a herpes virus (e.g., HSV–1 or a pseudorabies virus), or some other medium-to-large, DNA viruses.

These viruses are examples only and their use is not mandatory.

2. For rodent cell substrates, murine retroviruses are commonly used as specific ''model'' viruses.

B. Examples of Viruses Which Have Been Used in Viral Clearance Studies.

Several viruses which have been used in viral clearance studies. are listed in Table A–1. However, since these are merely examples, the use of any of the viruses in the table is not mandatory and manufacturers are invited to consider other viruses, especially those which may be more appropriate for their individual production processes. Generally, the process should be assessed for its ability to clear at least three different viruses with differing characteristics.

TABLE A–1.—EXAMPLES OF VIRUSES WHICH HAVE BEEN USED IN VIRAL CLEARANCE STUDIES

Virus	Family	Genus	Natural host	Genome	Envelope	Size	Shape	Resistance[1]
Vesicular stomatitis virus	Rhabdo	Vesiculovirus	Equine Bovine	RNA	yes	70x175 nm	Bullet	Low
Parainfluenza virus	Paramyxo	Paramyxovirus	Various	RNA	yes	100–200+ nm	Pleo/Spherical	Low
MuLV	Retro	Type C oncovirus	Mouse	RNA	yes	80–110 nm	Spherical	Low
Sindbis virus	Toga	Alphavirus	Human	RNA	yes	60–70 nm	Spherical	Low
BVDV	Flavi	Pestivirus	Bovine	RNA	yes	50–70 nm	Pleo-Spherical	Low
Pseudorabies virus	Herpes		Swine	DNA	yes	120–200 nm	Spherical	Medium
Poliovirus Sabin Type 1	Picorna	Enterovirus	Human	RNA	no	25–30 nm	Icosahedral	Medium
Encephalomyocarditis virus (EMC)	Picorna	Cardiovirus	Mouse	RNA	no	25–30 nm	Icosahedral	Medium
Reovirus 3	Reo	Orthoreovirus	Various	RNA	no	60–80 nm	Spherical	Medium
SV40	Papova	Polyomavirus	Monkey	DNA	no	40–50 nm	Icosahedral	Very high
Parvoviruses (canine, porcine)	Parvo	Parvovirus	Canine Porcine	DNA	no	18–24 nm	Icosahedral	Very high

[1] Resistance to physico-chemical treatments based on studies of production processes. Resistance is relative to the specific treatment and it is used in the context of the understanding of the biology of the virus and the nature of the manufacturing process. Actual results will vary according to the treatment. These viruses are examples only and their use is not mandatory.

Appendix 3

Statistical Considerations for Assessing Virus Assays

Virus titrations suffer the problems of variation common to all biological assay systems. Assessment of the accuracy of the virus titrations and reduction factors derived from them and the validity of the assays should be performed to define the reliability of a study. The objective of statistical evaluation is to establish that the study has been carried out to an acceptable level of virological competence.

1. Variation may arise within an assay as a result of dilution errors, statistical effects, and differences within the assay system that are either unknown or difficult to control.

These effects are likely to be greater when different assay runs are compared (between-assay variation) than when results within a single assay run are compared (within-assay variation).

2. Assay methods may be either quantal or quantitative. Quantal methods include infectivity assays in animals or in tissue-culture-infectious-dose (TCID) assays, in which the animal or cell culture is scored as either infected or not. Infectivity titers are then measured by the proportion of animals or culture infected. In quantitative methods, the infectivity measured varies continuously with the virus input. Quantitative methods include plaque assays where each plaque counted corresponds to a single infectious unit. Both quantal and quantitative assays are amenable to statistical evaluation.

3. The 95 percent confidence limits for results of within-assay variation normally should be on the order of ±0.5 $\log_{10}$ of the mean. Within-assay variation can be assessed by standard textbook methods. Between-assay variation can be monitored by the inclusion of a reference preparation, the estimate of whose potency should be within approximately 0.5 $\log_{10}$ of the mean estimate established in the laboratory for the assay to be acceptable. Assays with lower precision may be acceptable with appropriate justification.

4. The 95 percent confidence limits for the reduction factor observed should be calculated wherever possible in studies of clearance of ''relevant'' and specific ''model'' viruses. If the 95 percent confidence limits for the viral assays of the starting material are +s, and for the viral assays of the material after the step are +a, the 95 percent confidence limits for the reduction factor are in the equation below.

$$\pm\sqrt{S^2 + a^2}$$

Appendix 4

Probability of Detection of Viruses at Low Concentrations

At low virus concentrations (e.g., in the range of 10 to 1000 infectious particles per liter), it is evident that a sample of a few milliliters may or may not contain infectious particles. The probability, *p*, that this sample does not contain infectious viruses is:

$$p = ((V-v)/V)^n$$

where V (liter) is the overall volume of the material to be tested, v (liter) is the volume of the sample and n is the absolute number of infectious particles statistically distributed in V.

If V >> v, this equation can be approximated by the Poisson distribution:

$$p = e^{-cv}$$

where c is the concentration of infectious particles per liter.

or, $c = \ln p / -v$

As an example, if a sample volume of 1 mL is tested, the probabilities *p* at virus concentrations ranging from 10 to 1000 infectious particles per liter are:

c	10	100	1,000
p	0.99	0.90	0.37

This indicates that for a concentration of 1,000 viruses per liter, in 37 percent of sampling, 1 mL will not contain a virus particle.

If only a portion of a sample is tested for virus and the test is negative, the amount of virus which would have to be present in the total sample in order to achieve a positive result should be calculated and this value taken into account when calculating a reduction factor. Confidence limits at 95 percent are desirable. However, in some instances, this may not be practical due to material limitations.

Appendix 5

Calculation of Reduction Factors in Studies to Determine Viral Clearance

The virus reduction factor of an individual purification or inactivation step is defined as the $\log_{10}$ of the ratio of the virus load in the pre-purification material and the virus load in the post-purification material which is ready for use in the next step of the process. If the following abbreviations are used:

Starting material: vol v′; titer $10^{a'}$;
virus load: $v'.10^{a'}$,
Final material: vol v″; titer $10^{a''}$;
virus load: $v''.10^{a''}$,

the individual reduction factors Ri are calculated according to

$$10^{Ri} = v'.10^{a'} / v''.10^{a''}$$

This formula takes into account both the titers and volumes of the materials before and after the purification step.

Because of the inherent imprecision of some virus titrations, an individual reduction factor used for the calculation of an overall reduction factor should be greater than 1. The overall reduction factor for a complete production process is the sum logarithm of the reduction factors of the individual steps. It represents the logarithm of the ratio of the virus load at the beginning of the first process clearance step and at the end of the last process clearance step.

Appendix 6

Calculation of Estimated Particles per Dose

This is applicable to those viruses for which an estimate of starting numbers can be made, such as endogenous retroviruses. Example:

I. Assumptions

Measured or estimated concentration of virus in cell culture harvest = 10^6/mL
Calculated viral clearance factor = $>10^{15}$
Volume of culture harvest needed to make a dose of product = 1 liter ($l0^3$mL)

II. Calculation of Estimated Particles/Dose

$$\frac{\left(10^6 \text{ virus units / mL}\right)\times\left(10^3 \text{ mL / dose}\right)}{\text{Clearance factor} > 10^{15}} = \frac{10^9 \text{ particles / dose}}{\text{Clearance factor} > 10^{15}}$$

$= <10^{-6}$ particles/dose

Therefore, less than one particle per million doses would be expected.

Dated: May 1, 1996.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 96–11641 Filed 5–9–96; 8:45 am]

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federal register

Friday
May 10, 1996

Part V

Department of Transportation

Federal Aviation Administration

14 CFR Part 29

Airworthiness Standards: Transport Category Rotorcraft Performance; Final Rule

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 29

[Docket No. 24802; Amendment No. 29–40]

RIN 2120–AB36

Airworthiness Standards; Transport Category Rotorcraft Performance

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This rule adopts new and revised airworthiness standards for the performance of transport category rotorcraft. The changes define more clearly the factors for determining takeoff, climb, and landing performance requirements. These changes provide an improved level of safety associated with recent technological advances in the design of turboshaft engines and rotorcraft.

EFFECTIVE DATE: June 10, 1996.

FOR FURTHER INFORMATION CONTACT: T.E. Archer, Policy and Procedures Group (ASW–110), Rotorcraft Standards Staff, Aircraft Certification Service, Federal Aviation Administration, Fort Worth, Texas 76193–0110, telephone (817) 222–5126.

SUPPLEMENTARY INFORMATION:

Background

This final rule is based on a Notice of Proposed Rulemaking (NPRM) (Notice 90–1), issued January 2, 1990 (55 FR 698, January 8, 1990). The NPRM was preceded by an Advance Notice of Proposed Rulemaking (ANPRM) (Notice 85–19) issued October 9, 1985 (50 FR 42126, October 17, 1985), and by a public meeting on April 30, 1986 (51 FR 4504, February 5, 1986), in Fort Worth, Texas. A transcript of that meeting is contained in the docket for this rulemaking. Supplemental Notice of Proposed Rulemaking (SNPRM) (Notice 90–1A), issued June 15, 1994 (59 FR 33598, June 29, 1994), modified Notice 90–1 by including a minimum descent height of 15 feet.

Amendment 29–21 (48 FR 4373, January 26, 1983) revised the transport category rotorcraft airworthiness requirements to provide for an increased level of safety in several areas, including performance. Subsequently, a Federal Aviation Administration (FAA) program to develop guidance material (Advisory Circulars 27–1 and 29–2A) for certification of rotorcraft in accordance with the requirements of Title 14 of the Code of Federal Regulations (Title 14) part 29 (part 29) revealed a need for some additions to and clarification of the provisions of Amendment 29–21. Those additions and clarification are included in this amendment.

Amendment 29–21 modified the applicability limits of Categories A and B of Transport Category Rotorcraft. Category A rotorcraft must meet a higher level of safety, including the requirement to have multiple engines, and be able to continue safe flight after an engine failure. Category B rotorcraft may be either single or multiengine, but the changes adopted in Amendment 29–21 limited this category further to a maximum capacity of nine passengers and 20,000 pounds gross weight. No changes are made to those limits in this amendment.

A significant element of Notice 90–1 was a proposed minimum climb gradient for the Category A takeoff path. This standard was proposed to standardize the climb gradient for helicopters regardless of their airspeeds and to facilitate heliport planning. The present standard requires a minimum rate of climb for the takeoff path; however, recently certificated rotorcraft, as well as most rotorcraft currently under development, produce maximum rates of climb at higher airspeeds than the previous generation of rotorcraft. For a specific rate of climb, the climb gradient decreases as climb airspeed increases. This results in a shallower climb gradient for modern, high-speed rotorcraft than for older, slow-speed rotorcraft. Notice 90–1 proposed a minimum climb gradient based on the present rate-of-climb requirement and the lower airspeed of older rotorcraft. At the time Notice 90–1 was issued, FAA analysis suggested that this change would have involved an acceptably small weight (payload) penalty. However, more precise data supplied by the commenters in response to the notice indicate there would be a payload penalty of 450 pounds or greater for a current 10,000-pound class helicopter. This could represent as much as 20 to 25 percent of the passenger payload, which one commenter characterized as totally unacceptable. Upon reconsideration, the FAA agrees that the proposal would have a significantly more burdensome effect and would not be cost beneficial, and as noted in the following discussion, the proposal for requiring minimum climb gradient is not adopted in this rule.

All interested persons have been given an opportunity to participate in the making of these amendments, and due consideration has been given to all comments received. Except for the change described above and for the nonsubstantive, editorial, and clarifying changes as discussed herein, the proposals have been adopted as proposed.

Discussion of Comments

Five commenters each responded to Notices 85–19 and 90–1. These commenters represent worldwide manufacturers, operators, and airworthiness authorities. The commenters' recommendations and the suggested changes are summarized in the following discussions. Four commenters responded to Notice 90–1A and all agreed with that proposal.

14 CFR 29.1 Applicability

Notice 90–1 proposed to change the reference in paragraph (e) from §§ 29.79 to 29.87, which is redesignation of the section number for the height-velocity envelope. There were no comments; therefore, the proposal is adopted.

New 14 CFR 29.49 Performance at Minimum Operating Speed (Old § 29.73)

Notice 90–1 proposed to redesignate § 29.73 as § 29.49 to relocate the requirements for helicopter hover performance. For transport category helicopters, hover performance is analogous to the stall speed for transport category airplanes and provides the basis for all other performance requirements. Therefore, by placing the requirements for hovering performance first, the other requirements more logically follow.

One commenter proposes a requirement for one-engine-inoperative (OEI) hover performance both in and out-of-ground effect (OGE). This comment, also made in response to the ANPRM, is beyond the scope of this rule as proposed in the notice.

This commenter also recommends that OGE controllability (in 17-knot winds from any direction) should also be required. The FAA disagrees. Past FAA policy has permitted OGE performance to be presented in zero wind if a minimum of yaw control remains (i.e., must be able to generate a positive yaw rate) or to be demonstrated with some wind condition if the demonstrated conditions are clearly identified in the Rotorcraft Flight Manual (RFM). The validity of this policy has been borne out by good service experience; therefore, the 17-knot criteria are not considered necessary in determining OGE controllability. Therefore, the FAA considers the calm-wind OGE hover performance data with no related controllability limit are the minimum data that should be provided, and the amendment is adopted as proposed. The

requirement to provide performance information about OGE hover and the maximum safe wind for the data presented is clarified in the new § 29.1587(a)(6) and revised § 29.1587(b)(8).

14 CFR 29.51 Takeoff Data: General

Notice 90–1 proposed to change the sections referenced in the introductory text of paragraph (a) to correspond to the applicable sections numbered in accordance with these new amendments. No comments were received; therefore, the proposal is adopted as proposed.

14 CFR 29.53 Takeoff: Category A

This proposal would separate, in the text, the Category A takeoff requirement from the definition of a decision point. No comments were received; therefore, the proposal is adopted as proposed.

New 14 CFR 29.55 Takeoff Decision Point: Category A

Notice 90–1 proposed to add this new section to redefine the takeoff critical decision point (CDP) previously contained in § 29.53; it further proposed to remove the requirement to identify the CDP by height and airspeed, since height alone or other factors may be more appropriate. A commenter suggests that the section title and other references to ''critical decision point'' be changed to ''takeoff decision point (TDP).'' The commenter notes that TDP is compatible with the term ''landing decision point (LDP)'' already in other regulatory parts. The FAA agrees; accordingly, ''critical decision point'' is changed to ''takeoff decision point.''

Additionally, a commenter to § 29.59 states that engine failure and the TDP do not occur at the same time because of necessary pilot-recognition time. The FAA agrees that a time interval for pilot recognition of the engine failure must be included when establishing the TDP. Calculating a pilot-recognition time interval when determining the TDP is a natural part of the TDP-determining process. Current industry practice already adequately considers this pilot-recognition time interval in determining the TDP. Therefore, to explicitly state this requirement in the regulations imposes no additional economic burden on manufacturers. Also, to harmonize Title 14 and the Joint Aviation Requirements (JAR's), the certification requirements for the Joint Aviation Authorities (JAA) of Europe, an explicit adoption of the pilot-recognition time interval is necessary. Therefore, since a pilot-recognition time interval is currently being used by manufacturers, and the FAA and the manufacturers are interested in harmonizing Title 14 and the JAR's, a new paragraph (c) has been added to § 29.55 to require that a pilot-recognition time interval be included in the TDP determination.

This section is adopted with changes as discussed.

14 CFR 29.59 Takeoff Path: Category A

Notice 90–1 proposed to move the rejected takeoff requirements to a new § 29.62 and more clearly define the takeoff path from the start of the takeoff to completion at 1,000 feet above the takeoff surface. It also proposed the new phrase ''critical decision point,'' now changed to ''takeoff decision point'' as explained in new § 29.55. The most significant proposed change was to establish minimum climb gradients along the takeoff path. Present requirements specify only a rate of climb. The use of gradients would have assisted heliport designers and provided additional safe ground clearance. The FAA estimated that inclusion of these gradients would introduce only a slight performance penalty. However, as discussed earlier, more precise data submitted by commenters indicate that adopting these gradients would result in an unanticipated decrease in the payload of a 10,000-pound class rotorcraft. Therefore, present rate-of-climb requirements are retained; the proposed minimum climb gradient is not adopted; and the remaining paragraphs of § 29.59 are renumbered accordingly.

One commenter proposes that a new section be introduced to require information on the takeoff path acceleration segment distance when accelerating from V_{TOSS} to V_y and that § 29.1587 also be amended to require these data. The commenter's proposal is beyond the scope of Notice 90–1; therefore, the proposal is not included in the amendment as adopted but may be appropriate for future rulemaking.

Another commenter disagrees that engine failure and CDP (now TDP) occur at the same time. The FAA agrees as discussed previously under § 29.55. Accordingly, the proposed § 29.59(a)(2) has been reworded by changing critical decision point to engine failure point; and by adding the phrase, ''. . . continue to the TDP, and then . . .'' to paragraph (a)(3). These additions clarify that consideration of the time interval between engine failure and the pilot's recognition of the failure is necessary in establishing TDP.

Notice 90–1, with respect to loss of altitude after engine failure, proposed no minimum height during descent to attain V_{TOSS} except that touchdown should not occur. Also, Notice 90–1 proposed that a minimum ground clearance be determined during certification and the data included in the RFM. Several commenters objected to the proposal and stated that a minimum ground clearance value should be specified in the rule. Wide support was expressed by European authorities, manufacturers, and operators to limit the descent to not less than 15 feet above the takeoff surface. Also, this minimum height was reflected in the European JAA, Notice of Proposed Amendment (NPA) 29–2, Preliminary Issue 1. However, since Notice 90–1 proposed to eliminate the existing 35-foot minimum height of part 29, requiring a new minimum height of a specified value in excess of that proposed was more stringent than that proposed in Notice 90–1. Therefore, the FAA issued Notice 90–1A to include a minimum descent height of 15 feet and all commenters agreed. Hence, the minimum descent height of 15 fee is adopted as proposed by Notice 90–1A. However, the paragraph is shown as (e) rather than (g) as proposed by Notice 90–1A due to renumbering as discussed previously.

New 14 CFR 29.60 Elevated Heliport Takeoff Path: Category A

Notice 90–1 proposed to add this section to introduce the requirements for pinnacle takeoff path, Category A. However, two commenters suggest using the term ''elevated'' rather than ''pinnacle'' since ''elevated'' is a more common term. The FAA agrees, and the word ''pinnacle'' has been replaced with ''elevated heliport'' wherever used. Several commenters also recommend that the requirement for takeoff climb gradients be deleted from this section. Therefore, as in the ground-level takeoff path, the climb gradients proposed for this section have also been removed because data submitted by commenters indicate that adopting these gradients would result in an unanticipated decrease in payload.

However, the FAA notes that the proposal for this section was not clear in Notice 90–1. The section, as proposed, would require a continuous maneuver from the start of the takeoff unit reaching 1,000 feet above the takeoff surface with two specific rate-of-climb requirements at 200 and 1,000 feet above the takeoff surface. A continuous climb was never intended by the FAA. For example, if the descent below the takeoff surface is 200 feet, using a continuous climb standard would require a total initial climb of 400 feet to regain a point 200 feet above the takeoff surface. Therefore, climbing at a rate of 100 feet per minute would take

4 minutes to regain a point 200 feet above the takeoff surface while the current One Engine Inoperative (OEI) standards only require that 2½ minutes of emergency power be available. Hence, the time for this descent-climb would not be compatible with the time-limited OEI power level that is permitted. Therefore, this paragraph has been clarified to indicate that the distances to be measured will be the vertical magnitude of any descent below the takeoff surface and the horizontal distance from the start of the takeoff to the point where a positive rate of climb is established at an airspeed of at least V_{TOSS}. This will be considered to be the end of the takeoff distance. (See § 29.61.) From the end of the takeoff distance, climb data will be used for the remainder of takeoff path planning. The rate-of-climb requirements at 200 and 1,000 feet above the takeoff surface will remain the same but will be clearly identified as separate requirements and not a part of a continued takeoff maneuver. Climb gradients were also included in the proposal but, as previously discussed, are not adopted. This section is adopted with changes as discussed.

New 14 CFR 29.61 Takeoff Distance: Category A

Notice 90–1 proposed to add a new section to define more clearly the parameters to be used in determining takeoff distance. No comments were received on this proposal. However, in view of the previous discussion of elevated heliports and the changes to § 29.60, a second paragraph is added to more clearly define takeoff distances. Also, as discussed for the new § 29.59, a requirement for considering the pilot recognition interval following engine failure is recognized in the new § 29.61. The addition of § 29.61(b) states explicitly that the takeoff distance for elevated heliports is defined the same as that for nonelevated heliports except that there is no requirement that the rotorcraft remain at least 35 feet above the takeoff surface. This provision harmonizes Title 14 and the JAR. Section 29.61(b) relieves applicants from the requirement to attain and maintain at least 35 fee of altitude when determining the takeoff distance from an elevated heliport. Thus, the takeoff distance will be shorter for rotorcraft that take off from an elevated heliport. Thus, the takeoff distance will be shorter for rotorcraft that take off from an elevated heliport that the distance needed to reach 35 feet above the takeoff surface as required by § 29.61(a) for rotorcraft that take off from a nonelevated heliport. This reduction in takeoff distance will result from an exchange of the inherent altitude of the elevated heliport for airspeed and subsequently rate of climb. The FAA has determined that this relieving provision will neither increase the economic burden on any applicant nor increase the scope of this rule. Therefore, the proposal is adopted with the noted changes.

New 14 CFR 29.62 Rejected Takeoff: Category A

Notice 90–1 proposed to separate the text of the rejected takeoff criteria from the takeoff path section and impose the restriction for the use of only primary controls while airborne. No comments were received; therefore, the proposal is adopted with the change of CDP to TDP, the change of ''takeoff decision'' to ''engine failure,'' and the addition of ''the rotorcraft continuing to takeoff decision point,'' as explained in the discussion of new § 29.55.

New 14 CFR 29.64 Climb: General

This new section relocates and clarifies the general climb requirements. No comments were received; therefore, the proposal is adopted without change.

14 CFR 29.65 Climb: All Engines Operating

Notice 90–1 proposed to add a general requirement to determine Category a rotorcraft climb performance. Currently Category A rotorcraft climb performance is required only when V_{NE} (never-exceed speed) is less than best climb speed (V_Y) at sea level. No comments were received; therefore, the proposal is adopted without change.

14 CFR 29.67 Climb: One-engine-Inoperative

Notice 90–1 proposed to include the takeoff climb gradients as a part of the general climb requirement, as well as the OEI climb requirements to be met at 200 and 1,000 feet above the takeoff surface.

Commenters recommend that the climb gradient requirements be removed. The FAA agrees because data submitted by commenters indicate that adopting these gradients would result in an unanticipated decrease in payload. Therefore, the proposed climb gradient requirements are not adopted. However, the rate of climb requirements are adopted as proposed. Also, various clarifying word changes have been made including adding the words ''climb following'' before ''takeoff'' in paragraph (a)(2)(ii) to clarify that the unfavorable center of gravity applies to the climb following takeoff. The proposal is adopted with the noted changes.

14 CFR 29.75 Landing: General

Notice 90–1 proposed to revise the general landing requirements to separate specific requirements and to provide references to those specific landing requirement sections. No comments were received; therefore, the proposal is adopted without change.

14 CFR 29.77 Landing Decision Point

Notice 90–1 proposed to add the new requirement for designation of a landing decision point (LDP), which has been an industry practice although not required in all recent Category A certifications. No comments were received; therefore, the proposal is adopted without change except for clarifying that, in accordance with the discussion for § 29.55, pilot recognition time must be considered.

14 CFR 29.79 Landing: Category A

Notice 90–1 proposed to establish the Category A landing requirements as a separate section with only minor revision from the present requirements. One commenter discusses studies and computer predictions for approaches and landings at elevated heliports but does not propose any changes. Since no changes were recommended, and the FAA does not see a need for any changes based on the commenters' discussion, the proposal is adopted without change.

New 14 CFR 29.81 Landing Distance: Category A

Notice 90–1 proposed a new section to require landing distances to be determined from specific heights. One commenter suggests that the proposed flight profile between LDP and touchdown using an elevated heliport is unduly restrictive. This comment was based on the commenter's concern that the proposal would require consideration of a 25-foot high screen at the approach edge of the elevated heliport. The FAA notes that this is not the intent of this section. The proposed horizontal landing distance determined from a point 25 feet higher than the elevated heliport need not be contained within the heliport landing surface. ''Pinnacle'' has been changed to ''elevated heliport'' in accordance with previous discussions. Therefore, the proposal is adopted with the change as noted.

New 14 CFR 29.83 Landing: Category B

Notice 90–1 proposed a new § 29.83 that included moving the Category B landing requirement presently in § 29.75(c) into this new section and required landing distances to be determined power-on rather than power-off. One commenter suggests

deleting the requirement to avoid the unsafe area of the height-velocity (HV) envelope since Category B rotorcraft with nine or fewer passengers and less than 20,000 pounds do not have the HV envelope as a limitation and may transit the unsafe area of the HV envelope during landing. The FAA disagrees. While the commenter is correct about the HV envelope not being a limitation for Category B rotorcraft with nine or fewer passengers, the FAA cannot agree with presenting data that include normal operations within the unsafe area of the HV envelope. Certain operations (e.g., external loads and hoist work) are not necessarily limited by the type certification HV envelope; however, the operator still should be aware that the operations do not involve normal procedures, and the operator should evaluate the risk in accordance with the applicable regulations (e.g., part 133). Therefore, the proposal is adopted without change.

New 14 CFR 29.85 Balked Landing: Category A (Old § 29.77)

Notice 90–1 proposed to redesignate present § 29.77 as a new § 29.85, to clarify the relationship between the landing decision point and balked landing, and to remove the prohibition against descending below 35 feet above the landing surface. The proposal only specified that the rotorcraft ''not touch down'' during descent. One commenter proposes that some minimum height be required. As previously discussed under § 29.59, the FAA agrees; however, Notice 90–1 proposed to allow the rotorcraft to descend below the current 35-foot height as long as it does not touch down. Therefore, the FAA issued Notice 90–1A to include the 15-foot minimum descent height. Three commenters to Notice 90–1A fully agreed with the proposed changes. One commenter agreed provided the working for § 29.85(c) read identically to the wording of Notice 90–1. However, it was necessary to amend the wording in proposed paragraph (c) to add the minimum descent height restriction requirements. Otherwise, the wording is identical. Also, as previously discussed the term ''elevated'' will be used rather than ''pinnacle.'' Therefore, the proposal is adopted by adding the 15-foot minimum descent height and the amended wording to paragraph (c) and by adding the phrase ''failed and failure recognized'' to paragraph (b) to specify that the time interval for pilot recognition of engine failure must be considered as discussed in § 29.55.

New 14 CFR 29.87 Height-velocity Envelope (Old § 29.79)

Notice 90–1 proposed to redesignate § 29.79 as a new § 29.87 and to revise the engine power conditions to be used. No comments were received; therefore, the proposal is adopted with only editorial changes.

14 CFR 29.1323 Airspeed Indicating System

Notice 90–1 proposed to change the term ''height-speed'' to ''height-velocity'' to agree with other changes in the proposal. No comments were received; therefore, the proposal is adopted without change.

14 CFR 29.1587 Performance Information

Notice 90–1 proposed to change this section to conform to other changes in the proposal. One commenter suggests requiring, as performance information, the steady gradient of climb for each weight, altitude, and temperature for which takeoff data are scheduled for the two conditions between the end of the takeoff and at 1,000 feet above the takeoff surface. The FAA does not agree. This would require a significant increase in the number of flight tests for compilation of data and for FAA verification of this data, with resulting significant adverse economic impact and no perceived safety benefits. As discussed with respect to the new § 29.49, the requirement to provide OGE performance data, including the maximum safe wind for the data presented, is added to the Category A requirements in § 29.1587(a)(6). Also, § 29.1587(b)(8) is revised to reflect that OGE performance data, including maximum safe wind for the data presented, is no longer optional. Even though the new paragraph (a)(6) and the revised paragraph (b)(8) were not proposed, they only require the presentation in the Rotorcraft Flight Manual of the new OGE performance data, including the maximum wind for the data presented. The collection of the data is now required by the new § 29.49. New paragraph (a)(6) and revised paragraph (b)(8) state explicitly what would otherwise be required during the certification process to demonstrate compliance with the new required § 29.49. In addition to clarifying § 29.49(c), the new paragraph (a)(6) for Category A rotorcraft and the revised paragraph (b)(8) for Category B rotorcraft have identical provisions and additionally harmonize the FAR and the JAR. Based on these factors, the minimal burden placed on manufacturers of presenting the data that they are required to develop, and the remote likelihood of an adverse comment, it is unnecessary to solicit prior public comment on these nonsubstantive changes. Therefore, the proposal is adopted with the noted changes.

Regulatory Evaluation Summary

Changes to federal regulations must undergo several economic analyses. First, Executive Order 12866 directs Federal agencies to promulgate new regulations or modify existing regulations only if the potential benefits to society outweigh the potential costs. Second, the Regulatory Flexibility Act of 1980 requires agencies to analyze the economic impact of regulatory changes on small entities. Finally, the Office of Management and Budget directs agencies to assess the effects of regulatory changes on international trade. In conducting these assessments, the FAA has determined that this rule: (1) Will generate benefits exceeding its costs and is not ''significant'' as defined in Executive Order 12866; (2) is not ''significant'' as defined in DOT's Policies and Procedures; (3) will not have a significant impact on a substantial number of small entities; and (4) will not impact international trade. These analyses, available in the docket, are summarized below.

Cost/Benefit Analysis

The rule includes 31 changes to 21 sections of part 29. Twenty eight of the changes are either editorial in nature or update the regulations to correspond with current technology. Three changes, as discussed below, were singled out for study because they are more substantive in terms of cost and/or benefit impact. The FAA has determined that these requirements will have no or negligible economic impacts on manufacturers and operators.

Section 29.49(b)—Performance at Minimum Operating Speed (Category B Hover Performance). This rule renumbers § 29.73 to 29.49, deletes paragraph (b)(2), and removes the minimum hover performance requirement for Category B helicopters (but still requires that hover performance data be developed and provided by the manufacturer). There will be no cost impact resulting from this change, since test requirements are unchanged and design changes are not required. Although the same amount of hover performance data will still be required from manufacturers, operators will benefit by being able to capitalize on a small increase in gross weight and payload.

Section 29.49(c)—Performance at Minimum Operating Speed (Out-of-

Ground Effect Hover Performance). The rule will require that manufacturers provide out-of-ground effect (OGE) hover ceiling data to operators. Manufacturers have historically provided this information on a voluntary basis. Industry sources estimate that requiring OGE hover data will add, at most, an additional 3 to 5 flight test hours. At a cost of $24,800 per flight test hour, this represents an additional cost to manufacturers of $74,400 to $124,000 (in 1994 dollars) per certification.

OGE hover performance data is needed by operators that conduct external lift operations. If an operator were to conduct external lift operations without OGE hover data, the operator might pick up excessively heavy loads. While a single excessive load would not necessarily lead to an accident, it could create excessive stress on the dynamic components of the helicopter that could eventually lead to fatigue failure of a critical component and, subsequently, an accident. The expected benefit of averting a single accident entailing just one serious injury and/or moderate damage to the helicopter would easily exceed the upper-bound certification cost of $124,000.

Other advantages of requiring that manufacturers provide OGE hover data are that: (1) Operators will no longer be concerned that manufacturers might arbitrarily stop providing the data, (2) operators may feel more confident about the data because the FAA would be approving it, and (3) the FAA can assure uniformity in the presentation of data between manufacturers.

Section 29.83—Landing: Category B. The rule will require that approach and landing tests for Category B rotorcraft be made with power on rather than with engine power off. This is a more normal flight profile. This change will benefit pilots by providing more useful data in the flight manual for flight planning purposes since pilots normally plan for power-on landings. This will be particularly useful if a rotorcraft is operating at or near maximum gross weight in or around unimproved landing areas where landing distances are more critical. This will also increase the safety of test pilots since they will be required to perform fewer power-off tests. There are no or negligible additional costs associated with this change.

Regulatory Flexibility Determination

The Regulatory Flexibility Act of 1980 (RFA) was enacted by Congress to ensure that small entities are not unnecessarily and disproportionately burdened by government regulations. The RFA requires a Regulatory Flexibility Analysis if a proposed or final rule would have a significant economic impact, either detrimental or beneficial, on a substantial number of small entities. FAA Order 2100.14A, Regulatory Flexibility Criteria and Guidance, prescribes standards for complying with RFA review requirements in FAA rulemaking actions. The Order defines ''small entities'' in terms of size thresholds, ''significant economic impact'' in terms of annualized cost threshold, and ''substantial number'' as a number which is not less than eleven and which is more than one-third of the small entities subject to the proposed or final rule.

The rule will affect manufacturers and operators of future type-certificated transport category rotorcraft. For manufacturers, Order 2100.14A specifies a size threshold for classification as a small entity as 75 or fewer employees. Since no part 29 rotorcraft manufacturer has 75 or fewer employees, the rule will not have significant economic impact on a substantial number of small manufacturers. For operators, the benefits of increased payloads would probably not exceed the annualized thresholds specified in the Order; consequently, the rule will not have a significant economic impact on a substantial number of small operators.

International Trade Impact

The rule will have little or no impact on trade for either U.S. firms doing business in foreign markets or foreign firms doing business in the United States.

Federalism Implications

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that these amendments do not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

Conclusion

For the reasons discussed in the preamble, and based on the findings in the Regulatory Flexibility Determination and the International Trade Impact Analysis, the FAA has determined that this regulation is not a significant regulatory action under Executive Order 12866. In addition, the FAA certifies that these changes will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. All changes are found to have negligible or no cost impacts. Small entities are not affected because transport rotorcraft are manufactured by large entities, and trade is not affected since foreign manufacturers also must comply with the requirements of part 29. This proposal is considered to be nonsignificant under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979). A regulatory evaluation of the changes, including a Regulatory Flexibility Determination and International Trade Impact Analysis, has been placed in the docket. A copy may be obtained by contacting the person identified under **FOR FURTHER INFORMATION CONTACT.''**

List of Subjects in 14 CFR Part 29

Air transportation, Aircraft, Aviation safety, Rotorcraft, Safety.

The Amendment

In consideration of the foregoing, the Federal Aviation Administration amends part 29 of Title 14, Code of Federal Regulations (14 CFR part 29) as follows:

PART 29—AIRWORTHINESS STANDARDS: TRANSPORT CATEGORY ROTORCRAFT

1. The authority citation for part 29 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701, 44702, 44704.

2. Section 29.1 is amended by revising paragraph (e) to read as follows:

§ 29.1 Applicability.

* * * * *

(e) Rotorcraft with a maximum weight of 20,000 pounds or less but with 10 or more passengers seats may be type certificated as category B rotorcraft provided the Category A requirements of §§ 29.67(a)(2), 29.87, 29.1517, and subparts C, D, E, and F of this part are met.

* * * * *

3. Section 29.73 is redesignated as § 29.49 and revised to read as follows:

§ 29.49 Performance at minimum operating speed.

(a) For each Category A helicopter, the hovering performance must be determined over the ranges of weight, altitude, and temperature for which takeoff data are scheduled—

(1) With not more than takeoff power;

(2) With the landing gear extended; and

(3) At a height consistent with the procedure used in establishing the takeoff, climbout, and rejected takeoff paths.

(b) For each Category B helicopter, the hovering performance must be determined over the ranges of weight, altitude, and temperature for which certificate is requested, with—

(1) Takeoff power;

(2) The landing gear extended; and

(3) The helicopter in ground effect at a height consistent with normal takeoff procedures.

(c) For each helicopter, the out-of-ground effect hovering performance must be determined over the ranges of weight, altitude, and temperature for which certification is requested with takeoff power.

(d) For rotorcraft other than helicopters, the steady rate of climb at the minimum operating speed must be determined over the ranges of weight, altitude, and temperature for which certification is requested with—

(1) Takeoff power; and

(2) The landing gear extended.

4. Section 29.51 is amended by revising the introductory text of paragraph (a) to read as follows:

§ 29.51 Takeoff data: general.

(a) The takeoff data required by §§ 29.53, 29.55, 29.59, 29.60, 29.61, 29.62, 29.63, and 29.67 must be determined—

* * * * *

5. Section 29.53 is revised to read as follows:

§ 29.53 Takeoff: Category A.

The takeoff performance must be determined and scheduled so that, if one engine fails at any time the start of takeoff, the rotocraft can—

(a) Return to, and stop safely on, the takeoff area; or

(b) Continue the takeoff and climbout, and attain a configuration and airspeed allowing compliance with § 29.67(a)(2).

6. A new § 29.55 is added to read as follows:

§ 29.55 Takeoff decision point (TDP): Category A.

(a) The TDP is the first point from which a continued takeoff capability is assured under § 29.59 and is the last point in the takeoff path from which a rejected takeoff is assured within the distance determined under §29.62.

(b) The TDP must be established in relation to the takeoff path using no more than two parameters; e.g., airspeed and height, to designate the TDP.

(c) Determination of the TDP must include the pilot recognition time interval following failure of the critical engine.

7. Section 29.59 is revised to read as follows:

§ 29.59 Takeoff path: Category A.

(a) The takeoff path extends from the point of commencement of the takeoff procedure to a point at which the rotorcraft is 1,000 feet above the takeoff surface and compliance with § 29.67(a)(2) is shown. In addition—

(1) The takeoff path must remain clear of the height-velocity envelope established in accordance with § 29.87;

(2) The rotocraft must be flown to the engine failure point; at which point, the critical engine must be made inoperative and remain inoperative for the rest of the takeoff;

(3) After the critical engine is made inoperative, the rotorcraft must continue to the takeoff decision point, and then attain V_{TOSS};

(4) Only primary controls may be used while attaining V_{TOSS} and while establishing a positive rate of climb. Secondary controls that are located on the primary controls may be used after a positive rate of climb and V_{TOSS} are established but in no case less than 3 seconds after the critical engine is made inoperative; and

(5) After attaining V_{TOSS} and a positive a climb, the landing gear may be retracted.

(b) During the takeoff path determination made in accordance with paragraph (a) of this section and after attaining V_{TOSS} and a positive rate of climb, the climb must be continued at a speed as close as practicable to, but not less than, V_{TOSS} until the rotocraft is 200 feet above the takeoff surface. During this interval, the climb performance must meet or exceed that required by § 29.67(a)(1).

(c) From 200 feet above the takeoff surface, the rotorcraft takeoff path must be level or positive until a height 1,000 feet above the takeoff surface is attained with not less than the rate of climb required by § 29.67(a)(2). Any secondary or auxiliary control may be used after attaining 200 feet above the takeoff surface.

(d) Takeoff distance will be determined in accordance with § 29.61.

(e) During the continued takeoff, the rotorcraft shall not descend below 15 feet above the takeoff surface when the takeoff decision point is above 15 feet.

8. A new § 29.60 is added to read as follows:

§ 29.60 Elevated heliport takeoff path: Category A.

(a) The elevated heliport takeoff path extends from the point of commencement of the takeoff procedure to a point in the takeoff path at which the rotorcraft is 1,000 feet above the takeoff surface and compliance with § 29.67(a)(2) is shown. In addition—

(1) The requirements of § 29.59(a) must be met;

(2) While attaining V_{TOSS} and a positive rate of climb, the rotocraft may descend below the level of the takeoff surface if, in so doing and when clearing the elevated heliport edge, every part of the rotocraft clears all obstacles by at least 15 feet;

(3) The vertical magnitude of any descent below the takeoff surface must be determined; and

(4) After attaining V_{TOSS} and a positive rate of climb, the landing gear may be retracted.

(b) The scheduled takeoff weight must be such that the climb requirements of § 29.67 (a)(1) and (a)(2) will be met.

(c) Takeoff distance will be determined in accordance with § 29.61.

9. A new § 29.61 is added to read as follows:

§ 29.61 Takeoff distance: Category A.

(a) The normal takeoff distance is the horizontal distance along the takeoff path from the start of the takeoff to the point at which the rotorcraft attains and remains at least 35 feet above the takeoff surface, attains and maintains a speed of at least V_{TOSS}, and establishes a positive rate of climb, assuming the critical engine failure occurs at the engine failure point prior to the takeoff decision point.

(b) For elevated heliports, the takeoff distance is the horizontal distance along the takeoff path from the start of the takeoff to the point at which the rotorcraft attains and maintains a speed of at least V_{TOSS} and establishes a positive rate of climb, assuming the critical engine failure occurs at the engine failure point prior to the takeoff decision point.

10. A new § 29.62 is added to read as follows:

§ 29.62 Rejected takeoff: Category A.

The rejected takeoff distance and procedures for each condition where takeoff is approved will be established with—

(a) The takeoff path requirements of §§ 29.59 and 29.60 being used up to the engine failure point, the rotorcraft continuing to takeoff decision point, and the rotorcraft landed and brought to a stop on the takeoff surface;

(b) The remaining engines operating within approved limits;

(c) The landing gear remaining extended throughout the entire rejected takeoff; and

(d) The use of only the primary controls until the rotorcraft is on the

ground. Secondary controls located on the primary control may not be used until the rotorcraft is on the ground. Means other than wheel brakes may be used to stop the rotorcraft if the means are safe and reliable and consistent results can be expected under normal operating conditions.

11. A new § 29.64 is added to read as follows:

§ 29.64 Climb: general.

Compliance with the requirements of §§ 29.65 and 29.67 must be shown at each weight, altitude, and temperature within the operational limits established for the rotorcraft and with the most unfavorable center of gravity for each configuration. Cowl flaps, or other means of controlling the engine-cooling air supply, will be in the position that provides adequate cooling at the temperatures and altitudes for which certification is requested.

12. Section 29.65 is amended by revising paragraph (a) to read as follows and by removing paragraph (c):

§ 29.65 Climb: all engines operating.

(a) The steady rate of climb must be determined—

(1) With maximum continuous power;

(2) With the landing gear retracted; and

(3) A V_y for standard sea level conditions and at speeds selected by the applicant for other conditions.

* * * * *

13. Section 29.67 is revised to read as follows:

§ Climb: one-engine-inoperative (OEI).

(a) For Category A rotorcraft, in the critical takeoff configuration existing along the takeoff path, the following apply:

(1) The steady rate of climb without ground effect, 200 feet above the takeoff surface, must be at least 100 feet per minute for each weight, altitude, and temperature for which takeoff data are to be scheduled with—

(i) The critical engine inoperative and the remaining engines within approved operating limitations, except that for rotorcraft for which the use of 30-second/2-minute OEI power is requested, only the 2-minute OEI power may be used in showing compliance with this paragraph;

(ii) The landing gear extended; and

(iii) The takeoff safety speed selected by the applicant.

(2) The steady rate of climb without ground effect at 1,000 feet above the takeoff surface must be at least 150 feet per minute for each weight altitude, and temperature for which takeoff data are to be scheduled with—

(i) The critical engine inoperative and the remaining engines at maximum continuous power including OEI maximum continuous power, if approved, or at 30-minute power for rotorcraft for which certification for use of 30-minute power is requested;

(ii) The most unfavorable center of gravity for climb following takeoff;

(iii) The landing gear retracted; and

(iv) The speed selected by the applicant.

(3) The steady rate of climb (or descent) in feet per minute, at each altitude and temperature at which the rotocraft is expected to operate and at any weight within the range of weights for which certification is requested, must be determined with—

(i) The critical engine inoperative and the remaining engines at maximum continuous power including OEI maximum continuous power, if approved, and at 30-minute power for rotorcraft for which certification for the use of 30-minute power is requested;

(ii) The landing gear retracted; and

(iii) The speed selected by the applicant.

(b) For multiengine Category B rotorcraft meeting the Category A engine isolation requirements, the steady rate of climb (or descent) must be determined at the speed for best rate of climb (or minimum rate of descent) at each altitude, temperature, and weight at which the rotorcraft is expected to operate, with the critical engine inoperative and the remaining engines at maximum continuous power including OEI maximum continuous power, if approved, and at 30-minute power for rotorcraft for which certification for the use of 30-minute power is requested.

14. Section 29.75 is revised as follows:

§ 29.75 Landing: general.

(a) For each rotorcraft—

(1) The corrected landing data must be determined for a smooth, dry, hard, and level surface;

(2) The approach and landing must not require exceptional piloting skill or exceptionally favorable conditions; and

(3) The landing must be made without excessive vertical acceleration or tendency to bounce, nose over, ground loop, porpoise, or water loop.

(b) The landing data required by §§ 29.77, 29.79, 29.81, 29.83, and 29.85 must be determined—

(1) At each weight, altitude, and temperature for which landing data are approved;

(2) With each operating engine within approved operating limitations; and

(3) With the most unfavorable center of gravity.

15. Section 29.77 is redesignated as § 29.85 and a new § 29.77 is added to read as follows:

§ 29.77 Landing decision point: Category A.

The landing decision point (LDP) must be established at not less than the last point in the approach and landing path at which a balked landing can be accomplished under § 29.85 with the critical engine failed or failing and with the engine failure recognized by the pilot.

16. Section 29.79 is redesignated as § 29.87 and a new § 29.79 is added to read as follows:

§ 29.79 Landing: Category A.

(a) For Category A rotorcraft—

(1) The landing performance must be determined and scheduled so that if the critical engine fails at any point in the approach path, the rotorcraft can either land and stop safely or climb out and attain a rotorcraft configuration and speed allowing compliance with the climb requirement of § 29.67(a)(2);

(2) The approach and landing paths must be established with the critical engine inoperative so that the transition between each stage can be made smoothly and safely;

(3) The approach and landing speeds must be selected by the applicant and must be appropriate to the type of rotorcraft; and

(4) The approach and landing path must be established to avoid the critical areas of the height-velocity envelope determined in accordance with § 29.87.

(b) It must be possible to make a safe landing on a prepared landing surface after complete power failure occurring during normal cruise.

17. A new § 29.81 is added to read as follows:

§ 29.81 Landing distance: Category A

The horizontal distance required to land and come to a complete stop (or to a speed of approximately 3 knots for water landings) from a point 50 feet above the landing surface (25 feet for Category A elevated heliport landing operations) must be determined from the approach and landing paths established in accordance with § 29.79.

18. A new § 29.83 is added to read as follows:

§ 29.83 Landing: Category B.

(a) For each Category B rotorcraft, the horizontal distance required to land and come to a complete stop (or to a speed of approximately 3 knots for water landings) from a point 50 feet above the landing surface must be determined with—

(1) Speeds appropriate to the type of rotocraft and chosen by the applicant to avoid the critical areas of the height-velocity envelope established under § 29.87; and

(2) The approach and landing made with power on and within approved limits.

(b) Each multiengined Category B rotorcraft that meets the powerplant installation requirements for Category A must meet the requirements of—

(1) Sections 29.79 and 29.81; or

(2) Paragraph (a) of this section.

(c) It must be possible to make a safe landing on a prepared landing surface if complete power failure occurs during normal cruise.

19. Redesignated § 29.85 is revised to read as follows:

§ 29.85 Balked landing: Category A.

For Category A rotocraft, the balked landing path must be established so that—

(a) With the critical engine inoperative, the transition from each stage of the maneuver to the next stage can be made smoothly and safely;

(b) With the critical engine failed and the failure recognized at the landing decision point on the approach path selected by the applicant, a safe climbout can be made at speeds allowing compliance with the climb requirements of § 29.67(a) (1) and (2); and

(c) The rotocraft does not descend below 15 feet above the landing surface. For elevated heliport operations, descent may be below the level of the landing surface provided the deck edge clearance of § 29.60 is maintained and the descent distance below the landing surface is determined.

20. Redesignated § 29.87 is revised to read as follows:

§ 29.87 Height-velocity envelope.

(a) If there is any combination of height and forward velocity (including hover) under which a safe landing cannot be made after failure of the critical engine and with the remaining engines (where applicable) operating within approved limits, a height-velocity envelope must be established for—

(1) All combinations of pressure altitude and ambient temperature for which takeoff and landing are approved; and

(2) Wright from the maximum weight (at sea level) to the highest weight approved for takeoff and landing at each altitude. For helicopters, this weight need not exceed the highest weight allowing hovering out-of-ground effect at each altitude.

(b) For single-engine or multiengine rotorcraft that do not meet the Category A engine isolation requirements, the height-velocity envelope for complete power failure must be established.

Section 29.1323 is amended by revising paragraph (b)(2)(ii) to read as follows:

§ 29.1323 Airspeed indicating system.

* * * * *

(b) * * *

(2) * * *

(ii) Avoidance of the critical areas of the height-velocity envelope as established under § 29.87.

* * * * *

22. Section 29.1587 is amended by revising (a)(4), (a)(5), (b)(3) and (b)(8) and adding a new (a)(6) to read as follows:

§ 29.1587 Performance information.

* * * * *

(a) * * *

(4) The rejected takeoff distance determined under § 29.62 and the takeoff distance determined under § 29.61 or § 29.63;

(5) The landing data determined under § 29.81 or § 29.83; and

(6) Out-of-ground effect hover performance determined under § 29.49 and the maximum safe wind demonstrated under the ambient conditions for data presented.

(b) * * *

(3) The landing distance, appropriate airspeed, and type of landing surface, together with all pertinent information that might affect this distance, including the effects of weight, altitude, and temperature;

* * * * *

(8) Out-of-ground effect hover performance determined under § 29.49 and the maximum safe wind demonstrated under the ambient conditions for data presented; and

* * * * *

Issued in Washington, DC, on May 2, 1996.

David R. Hinson,

Administrator.

[FR Doc. 96–11494 Filed 5–9–96; 8:45 am]

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Part VI

Department of Transportation

Federal Aviation Administration

14 CFR Parts 27 and 29

Rotorcraft Regulatory Changes Based on European Joint Aviation Requirements; Final Rule

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Parts 27 and 29

[Docket No. 28008; Amendment No. 27–33, 29–39]

RIN 2120–AF65

Rotorcraft Regulatory Changes Based on European Joint Aviation Requirements

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: The Federal Aviation Administration (FAA) is amending the airworthiness standards for normal and transport category rotorcraft. The changes revise airworthiness standards for performance, systems, propulsion, and airframes. The changes increase the regulatory safety level, clarify existing regulations, and standardize terminology. The changes are based on standards incorporated by the European Joint Aviation Authorities (JAA) for Joint Aviation Requirements (JAR) 27 and 29. These changes are intended to harmonize the U.S. rotorcraft airworthiness standards with the European JAR.

EFFECTIVE DATE: August 8, 1996.

FOR FURTHER INFORMATION CONTACT: Carroll Wright, Regulations Group Rotorcraft Directorate, Aircraft Certification Service, Federal Aviation Administration, Fort Worth, Texas 76193–0111, telephone (817) 222–5120.

SUPPLEMENTARY INFORMATION:

Background

These amendments are based on Notice of Proposed Rulemaking (NPRM) No. 94–36 published in the Federal Register on December 28, 1994 (59 FR 67068). That notice proposed to amend the airworthiness standards for both normal and transport category rotorcraft based on recommendations from the Aviation Rulemaking Advisory Committee (ARAC). By announcement in the Federal Register (57 FR 58846, December 11, 1992), the ''JAR/FAR 27 and 29 Harmonization Working Group'' was chartered by the ARAC. The working group included representatives from four major rotorcraft manufacturers (normal and transport) and representatives from Aerospace Industries Association of America, Inc. (AIA), Association Europeene des Constructeurs de Material Aerospatial (AECMA), Helicopter Association International (HAI), JAA, and the FAA Rotorcraft Directorate. This broad participation is consistent with FAA policy to involve all known interested parties as early as practicable in the rulemaking process.

The Harmonization Working Group was tasked with making recommendations to the ARAC regarding JAA Notices of Proposed Amendment (NPA's). The ARAC subsequently recommended that the FAA revise the airworthiness standards for normal and transport category rotorcraft to those currently in the JAR 27 and 29.

The FAA evaluated the ARAC recommendations and proposed changes to the rotorcraft airworthiness standards in 14 CFR parts 27 and 29 (parts 27 and 29). These proposed changes evolved from the FAA, JAA, and industry meetings of 1990–1992 and the ARAC recommendations of 1993. The changes proposed to (1) incorporate current design and testing practices into the rules by requiring additional performance data, (2) incorporate additional powerplant and rotor brake controls requirements, (3) incorporate bird-strike protection requirements, and (4) harmonize the certification requirements between parts 27 and 29 and the JAR. The proposals for part 27 included JAA's harmonized NPA's 27-Basic and 27–1, and the proposals for part 29 included NPA's 29-Basic and 29–1 through 29–5. This rule contains the harmonized rule language of those sections of the NPA's except for § 27.602 of NPA 27-Basic and § 29.602 of NPA 29–4.

In proposed rule, NPRM 94–36, there were several instances in which a few descriptive words were proposed to either be removed from or added to regulatory text. These word changes were adequately described in the amendatory language to NPRM 94–36 when that proposal was published in the Federal Register. However, at least one commenter misunderstood the amendatory language. Therefore, to avoid possible misunderstanding about the final rule language, the paragraphs with the minor rule language changes are reproduced in their entirety in this final rule. Also, the numbering of other regulations referenced in §§ 29.1587(a)(4) and (a)(5) has been changed, and a new § 29.1587(a)(6) has been added. The current § 29.1587(a)(6), which is being redesignated in this rule as § 29.1587(a)(7), was added by the Transport Category Rotorcraft Performance Rule published elsewhere in this issue of the Federal Register.

In this final rule, under the heading ''Appendix C to Part 27—Criteria for Category A,'' the NPRM 94–36 cites to Advisory Circular (AC) material have been removed since AC material is advisory only. A note has been added that informs the reader that there is appropriate guidance material available. Further, the requirement to meet § 29.571 standards for certification as a part 27 Category A rotorcraft has been removed from the Appendix C listing. The FAA has determined that the current § 27.571 contains sufficient certification standards to maintain an adequate level of safety for part 27 Category A rotorcraft, and an additional requirement of testing to § 29.571 standards is unnecessary.

Discussion of Comments

Interested persons have been afforded an opportunity to participate in the making of these amendments. Due consideration has been given to the comments received. Comments were received from the JAA, HAI, Transport Canada, and the United Kingdom Civil Aviation Authority (UKCAA).

The JAA agrees with the proposed rule and the effort to harmonize certification regulations of the U.S. and the European communities. To fulfill harmonization objectives, the JAA prepared an NPA identical to the NPRM and will publish the JAR final rule at the same time as this time as this final rule for parts 27 and 29.

HAI comments that the proposals faithfully reflect the recommendation made to the FAA by the ARAC on rotorcraft regulatory changes. HAI further comments that the NPRM reflects prudent rulemaking to increase safety, economic viability, and harmonization within realistic requirements and urges the adoption of the proposal.

Transport Canada comments that the NPRM was not the same as the ARAC recommendations in that there were changes in the nonregulatory sections (preamble) and in the proposed text of the rule. The commenter states that these changes cause concern because the discrepancies may lead to different interpretations. The commenter notes that the meaning of § 29.547 was changed because the word ''main'' had been removed in the ARAC recommendations but was not removed in the NPRM. This commenter also states that the requirements of §§ 29.547 and 29.917 are redundant because § 29.571 also requires the identification of the principal structural elements (PSE) that includes rotors and rotor drive systems with the establishment of the inspections and replacement times for those PSE's. Additionally, the commenter says that § 29.610 should state that it addresses only ''direct effects'' of lightning and electricity and

that indirect effects are covered elsewhere in §§ 29.954, 29.863, 29.1309, etc. This commenter also states that § 29.1309 should retain the reference to § 29.610. This commenter also suggests adding a new requirement and paragraph to Appendix B to part 29 that would require an additional, self-powered third attitude indicator.

The FAA agrees with Transport Canada that editorial changes between the ARAC recommendations and the NPRM are a concern because the differences may lead to different interpretations. To obviate this concern, editorial changes have been made in the final rule language to make it consistent with the ARAC recommended language. Also, the FAA agrees with Transport Canada that the word ''main'' had been removed from the introductory paragraph of § 29.547(c), (d), and (e) in the ARAC recommended language but, as previously discussed, had not been shown as removed in the NPRM rule language. However, the word ''main'' is being removed from this final rule.

The FAA does not agree with this commenter that §§ 29.547, 29.571, and 29.917 are redundant in requiring identification of principal structural elements (PSE's), which include rotors and rotor drive systems, and the establishment of the inspections, replacement times of those PSE's. Section 29.547(b) requires a design assessment for main and tail rotor structure components (rotor hub, blades, pitch control mechanisms, etc); § 29.571 requires fatigue evaluation of structural components; and § 29.917 requires a design assessment of the rotor drive system (drive shafts, transmission, gearboxes, etc). Therefore, these are non redundant requirements. The language is adopted as proposed.

The FAA agrees with the intent of this commenter's suggestion that § 29.610 should clearly indicate that it addresses only ''direct effects'' of lightning and electricity. However, this was achieved in the NPRM by adding the word ''structure'' between the words ''rotorcraft'' and ''must'' in § 29.610(a) to clarify that this paragraph applied to rotorcraft structure and not to systems and equipment. Accordingly, the language is adopted as proposed.

The FAA does not agree with this commenter that § 29.1309 should retain the reference to § 29.610. The NPRM added the word ''structure'' to § 29.610 to clarify that the paragraph applied to rotorcraft structure and not to systems and equipment. Since § 29.1309(h) applies to lightning protection of systems and equipment, it is inappropriate to reference § 29.610, which applies to lightning protection of structures. The commenter's proposal to retain the reference to § 29.610 is not adopted.

The FAA disagrees with this commenter's suggestion that a new requirement and paragraph be added to part 29, Appendix B, to require an additional, self-powered third attitude indicator. Part 29, Appendix B, paragraph VIII(a)(2) currently requires a standby attitude indicator that is independent of the aircraft electrical generating system. Additionally, part 29, Appendix B, paragraph VIII(b)(5)(iii) states, ''The equipment, systems, and installations must be designed so that one display of the information essential to the safety of flight that is provided by the instruments will remain available to a pilot, without additional crew-member action, after any single failure or combination of failures that is not shown to be extremely improbable * * *.'' Currently, the only practical design to meet the extremely improbable (10^{-9}) requirement of part 29, Appendix B, for the display of information essential to flight safety after a single failure or combination of failures is the design that uses a third attitude indicator powered by a source other than the aircraft electrical generating system. However, the FAA does not wish to limit future alternative designs that may meet the extremely improbable standard without a third attitude indicator. The suggestion of the commenter to add a requirement for a self-powered third attitude indicator is not adopted.

The UKCAA comments that Proposal No. 13 in NPRM 94–36 proposed to amend § 29.923(b)(3)(i), to require two applications of 2-minute power following each application of 30-second power, instead of the one application of 2-minute power previously proposed. The UKCAA fully supports the proposed changes in NPRM 94–36. However, the UKCAA further comments that since publication of NPRM 94–36, the FAA published Amendment 29–34 (59 FR 47764, September 16, 1994) that states in part, ''When conducted on a bench test, the test sequence must be conducted following stabilization at take-off power.'' The commenter states that the reason for adding this sentence, as stated in the preamble to Amendment 29–34, remains valid, and this sentence should therefore be included in the final rule developed from NPRM 94–36.

The FAA concurs with the UKCAA that the reason for adding the sentence, ''When conducted on a bench test, the test sequence must be conducted following stabilization at take-off power'' remains valid and the sentence should be retained in § 29.923(b)(3)(i). The sentence was adopted in Amendment 29–34 due to a commenter's statement that if the 5-minute takeoff power run to qualify the drive system is conducted as part of the endurance run, and the 30-second/2-minute OEI requirements are conducted on a bench test, then the takeoff power 5-minute run will be conducted twice on the same set of gears. The FAA did not intend to duplicate the takeoff power 5-minute run if the OEI requirements are conducted on a bench test, and the sentence was adopted for clarification. Since the omission of the sentence in NPRM 94–36 was inadvertent, since the reasons for including the sentence remain valid, and since the sentence is relieving in nature and does not place any additional burden on manufacturers, it is unnecessary to solicit prior public comment. Therefore, the sentence is restored as requested by the commenter.

After considering all of the comments, the FAA has determined that air safety and the pubic interest support adoption of the amendments with the changes noted.

Regulatory Evaluation Summary

Proposed changes to federal regulations must undergo several economic analyses. First, Executive Order 12866 directs that each Federal agency shall propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs. Second, the Regulatory Flexibility Act of 1980 requires agencies to analyze the economic effect of regulatory changes on small entities. Third, the Office of Management and Budget directs agencies to assess the effect of regulatory changes on international trade. In conducting these analyses, the FAA has determined that this rule: (1) would generate benefits that justify its costs and is not ''a significant regulatory action'' as defined in the Executive Order; (2) is nonsignificant as defined in DOT's Regulatory Policies and Procedures; (3) would not have a significant impact on substantial number of small entities; and (4) will lessen restraints on international trade. These analyses, available in the docket, are summarized below.

Cost-Benefit Analysis

All of the changes to part 27 and all but four of the changes to part 29 will impose no or insignificant costs on rotorcraft manufacturers since they largely reflect current design practices. In recent years, manufacturers have incorporated engineering and structural improvements into rotorcraft designs

that exceed minimum regulatory requirements with the aim of increasing operating efficiencies, payload capabilities, and marketability in world markets. Many of these improvements have also inherently improved safety codification of these improvement and other changes will ensure continuation of enhanced safety levels in future rotorcraft designs.

The changes will also increase harmonization and commonality between U.S. and European airworthiness standards. Harmonization will eliminate the need to comply with different FAA and JAA airworthiness requirements, thus reducing manufacturers' certification costs. Based on experience in a recent certification, one rotorcraft manufacturer indicated that complying with different FAA and JAA requirements resulted in several hundred thousand dollars of excessive certification costs (as related to all part 27 and 29 requirements). The duplicate certification costs avoided by the harmonized rule alone could outweigh the relatively modest increase in certification costs imposed by the few new requirements. Following is a summary of the four changes to part 29 that will impose additional costs totaling approximately $160,000 per type certification. The safety benefits of these changes are expected to easily exceed the incremental costs.

Section 29.547—Main and tail rotor structure. While manufacturers currently perform the design assessment as an integral part of the design requirements of § 29.917, there will be some incremental costs to formalize the existing information. These costs are included in the cost estimates of § 29.917 summarized below. Formal identification and assessment of critical component failures will increase safety by providing more comprehensive maintenance information to operators. The benefits of averting a single accident will exceed the relatively low incremental costs of compliance.

Section 29.631—Bird strike. Manufacturers indicate that present rotorcraft structures can withstand impacts with 2.2 pound birds; therefore, no incremental manufacturing costs are anticipated. Nonrecurring testing and analysis costs of the requirement are estimated to be $107,000 per type certification. A review of National Transportation Safety Board (NTSB) data for the period 1983–1991 reveals two rotorcraft accidents caused by bird strikes. One accident resulted in one serious injury, one minor injury, and substantial damage to the rotorcraft (tail rotor separation); in the other accident, the rotorcraft was destroyed but there were no injuries. There is at least an equal probability of such accidents in the future, given the tendencies toward higher operating speeds. The benefits of averting a single accident will exceed the incremental costs of the amendment.

Section 29.917—Design. The incremental costs to formalize existing design information for the rotor structure (§ 29.547 above) and drive system are estimated to total $47,000 per type certification. Formal identification and assessment of critical component failures of the rotor drive system will increase safety by providing more comprehensive maintenance information to operators. The benefits of averting a single accident caused directly or indirectly by a lack of relevant data would easily exceed the incremental costs.

Section 29.1587—Performance information. Since the required climb gradient data are already available from the results of flight tests required to obtain performance information, the only additional costs will be those associated with incorporating the data into the Flight Manual, estimated to total $6,000 per type certification. The availability and accuracy of performance data are paramount to operational safety. The benefits of averting a single accident caused directly or indirectly by a lack of relevant performance information will easily exceed the incremental costs.

Regulatory Flexibility determination

The Regulatory Flexibility Act of 1980 (RFA) was enacted by Congress to ensure that small entities are not unnecessarily and disproportionately burdened by Federal Regulations. The RFA requires a Regulatory Flexibility Analysis if a proposed rule would have ''a significant economic impact on a substantial number of small entities.'' Based on the criteria of FAA Order 2100.14A, the FAA has determined that the rule will not have a significant impact on a substantial number of small entities.

The rule will affect manufacturers of future type-certificated normal (part 27) and transport category (part 29) rotorcraft. For manufacturers, Order 2100.14A defines a small entity as one with 75 or fewer employees and a significant economic impact as annualized costs of $19,000 or more. The FAA has determined that the rule will not have a significant economic impact on a substantial number of small manufacturers since (1) no part 29 and only two part 27 rotorcraft manufacturers have 75 or fewer employees, and (2) the annualized certification costs of the rule are less than $19,000.

International Trade Impact Assessment

The rule will not constitute a barrier to international trade, including the export of American rotorcraft to other countries and the import of rotorcraft into the United States. Instead, the changes will harmonize with certification procedures of the JAA and thereby enhance free trade.

Conclusion

For the reasons discussed above, including the findings in the Regulatory Flexibility Determination and the International Trade Impact Analysis, the FAA has determined that this regulation is not a significant regulatory action under Executive Order 12866. In addition, the FAA certifies that this regulation will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. This regulation is considered nonsignificant under DOT Order 2100.5. A final regulatory evaluation of the regulation, including a final Regulatory Flexibility Determination and International Trade Impact Analysis, has been placed in the docket. A copy may be obtained by contacting the person identified under **FOR FURTHER INFORMATION CONTACT.**

List of Subjects in 14 CFR Parts 27 and 29

Air transportation, Aircraft, Aviation safety, Rotorcraft, Safety.

The Amendments

In consideration of the foregoing, the Federal Aviation Administration amends parts 27 and 29 of Title 14, Code of Federal Regulations (14 CFR parts 27 and 29) as follows:

PART 27—AIRWORTHINESS STANDARDS: NORMAL CATEGORY ROTORCRAFT

1. The authority citation for part 27 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701, 44702, 44704.

2. Section 27.1 is amended by adding a new paragraph (c) to read as follows:

§ 27.1 Applicability.

* * * * *

(c) Multiengine rotorcraft may be type certificated as Category A provided the requirements referenced in appendix C of this part are met.

3. Section 27.65 is amended by revising paragraphs (b)(2) introductory text and (b)(2)(ii) to read as follows:

§ 27.65 Climb: all engines operating.

* * * * *

(b) * * *

(2) The steady rate of climb must be determined—

* * * * *

(ii) Within the range from sea level up to the maximum altitude for which certification is requested;

* * * * *

4. Section 27.1141 is amended by redesignating existing paragraphs (c) and (d) as paragraphs (d) and (e) and by adding a new paragraph (c) to read as follows:

§ 27.1141 Powerplant controls: general.

* * * * *

(c) Each control must be able to maintain any set position without—

(1) Constant attention; or

(2) Tendency to creep due to control loads or vibration.

* * * * *

5. New § 27.1151 is added to read as follows:

§ 27.1151 Rotor brake controls.

(a) It must be impossible to apply the rotor brake inadvertently in flight.

(b) There must be means to warn the crew if the rotor brake has not been completely released before takeoff.

6. Part 27 is amended by adding a new appendix C to read as follows:

Appendix C to Part 27—Criteria for Category A

C27.1 General.

A small multiengine rotorcraft may not be type certificated for Category A operation unless it meets the design installation and performance requirements contained in this appendix in addition to the requirements of this part.

C27.2 Applicable part 29 sections. The following sections of part 29 of this chapter must be met in addition to the requirements of this part:

29.45(a) and (b)(2)—General.
29.49(a)—Performance at minimum operating speed.
29.51—Takeoff data: General.
29.53—Takeoff: Category A.
29.55—Takeoff decision point: Category A.
29.59—Takeoff Path: Category A.
29.60—Elevated heliport takeoff path: Category A.
29.61—Takeoff distance: Category A.
29.62—Rejected takeoff: Category A.
29.64—Climb: General.
29.65(a)—Climb: AEO.
29.67(a)—Climb: OEI.
29.75—Landing: General.
29.77—Landing decision point: Category A.
29.79—Landing: Category A.
29.81—Landing distance (Ground level sites): Category A.
29.85—Balked landing: Category A.
29.87(a)—Height-velocity envelope.
29.547(a) and (b)—Main and tail rotor structure.
29.861(a)—Fire protection of structure, controls, and other parts.
29.901(c)—Powerplant: Installation.
29.903(b) (c) and (e)—Engines.
29.908(a)—Cooling fans.
29.917(b) and (c)(1)—Rotor drive system: Design.
29.927(c)(1)—Additional tests.
29.953(a)—Fuel system independence.
29.1027(a)—Transmission and gearboxes: General.
29.1045(a)(1), (b), (c), (d), and (f)—Climb cooling test procedures.
29.1047(a)—Takeoff cooling test procedures.
29.1181(a)—Designated fire zones: Regions included.
29.1187(e)—Drainage and ventilation of fire zones.
29.1189(c)—Shutoff means.
29.1191(a)(1)—Firewalls.
29.1193(e)—Cowling and engine compartment covering.
29.1195(a) and (d)—Fire extinguishing systems (one shot).
29.1197—Fire extinguishing agents.
29.1199—Extinguishing agent containers.
29.1201—Fire extinguishing system materials.
29.1305(a) (6) and (b)—Powerplant instruments.
29.1309(b)(2) (i) and (d)—Equipment, systems, and installations.
29.1323(c)(1)—Airspeed indicating system.
29.1331(b)—Instruments using a power supply.
29.1351(d)(2)—Electrical systems and equipment: General (operation without normal electrical power).
29.1587(a)—Performance information.

Note: In complying with the paragraphs listed in paragraph C27.2 above, relevant material in the AC ''Certification of Transport Category Rotorcraft'' should be used.

PART 29—AIRWORTHINESS STANDARDS: TRANSPORT CATEGORY ROTORCRAFT

7. The authority citation for part 29 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701, 44702, 44704.

8. Section 29.547 is amended by revising the heading; by revising paragraph (a); by revising the introductory text in paragraphs (c), (d), and (e); by revising paragraph (e)(1)(ii); and by adding paragraph (b) to read as follows:

§ 29.547 Main and tail rotor structure.

(a) A rotor is an assembly of rotating components, which includes the rotor hub, blades, blade dampers, the pitch control mechanisms, and all other parts that rotate with the assembly.

(b) Each rotor assembly must be designed as prescribed in this section and must function safely for the critical flight load and operating conditions. A design assessment must be performed, including a detailed failure analysis to identify all failures that will prevent continued safe flight or safe landing, and must identify the means to minimize the likelihood of their occurrence.

(c) The rotor structure must be designed to withstand the following loads prescribed in §§ 29.337 through 29.341 and 29.351:

* * * * *

(d) The rotor structure must be designed to withstand loads simulating—

* * * * *

(e) The rotor structure must be designed to withstand the limit torque at any rotational speed, including zero.

In addition:

(1) * * *

* * * * *

(ii) For the main rotor, the limit engine torque specified in § 29.361.

* * * * *

9. Section 29.610 is amended by revising the heading; by revising paragraph (a); and by adding a new paragraph (d) to read as follows:

§ 29.610 Lightning and static electricity protection.

(a) The rotorcraft structure must be protected against catastrophic effects from lightning.

* * * * *

(d) The electric bonding and protection against lightning and static electricity must—

(1) Minimize the accumulation of electrostatic charge;

(2) Minimize the risk of electric shock to crew, passengers, and service and maintenance personnel using normal precautions;

(3) Provide an electrical return path, under both normal and static electricity on the functioning of essential electrical and electronic equipment.

(4) Reduce to an acceptable level the effects of lightning and static electricity on the functioning of essential electronic equipment.

10. Section 29.629 is revised to read as follows:

§ 29.629 Flutter and divergence.

Each aerodynamic surface of the rotorcraft must be free from flutter and divergence under each appropriate speed and power condition.

11. Section 29.631 is added before the undesignated center heading, ''Rotors'' to read as follows:

§ 29.631 Bird strike.

The rotorcraft must be designated to ensure capability of continued safe flight and landing (for Category A) or safe landing (for Category B) after impact with a 2.2-lb (1.0 kg) bird when

the velocity of the rotorcraft (relative to the bird along the flight path of the rotorcraft) is equal to V_{NE} or V_H (whichever is the lesser) at altitudes up to 8,000 feet. Compliance must be shown by tests or by analysis based on tests carried out on sufficiently representative structures of similar design.

12. Section 29.917 is amended by redesignating existing paragraph (b) as (c) and by adding a new paragraph (b) to read as follows:

§ 29.917 Design.

* * * * *

(b) Design assessment. A design assessment must be performed to ensure that the rotor drive system functions safely over the full range of conditions for which certification is sought. The design assessment must include a detailed failure analysis to identify all failures that will prevent continued safe flight or safe landing and must identify the means to minimize the likelihood of their occurrence.

* * * * *

13. Section 29.923 is amended by revising paragraph (b)(3)(i) to read as follows:

§ 29.923 Rotor drive system and control mechanism tests.

* * * * *

(b) * * *

(3) * * *

(i) Immediately following any one 5-minute power-on run required by paragraph (b)(1) of this section, simulate a failure for each power source in turn, and apply the maximum torque and the maximum speed for use with 30-second OEI power to the remaining affected drive system power inputs for not less than 30 seconds. Each application of 30-second OEI power must be followed by two applications of the maximum torque and the maximum speed for use with the 2 minute OEI power for not less than 2 minutes each; the second application must follow a period at stabilized continuous or 30 minute OEI power (whichever is requested by the applicant). At least one run sequence must be conducted from a simulated ''flight idle'' condition. When conducted on a bench test, the test sequence must be conducted following stabilization at take-off power.

* * * * *

14. Section 29.1305 is amended by redesignating existing paragraphs (a)(6) through (a)(25) as paragraphs (a)(7) through (a)(26) and by adding a new paragraph (a)(6) to read as follows:

§ 29.1305 Powerplant instruments

* * * * *

(a) * * *

(6) An oil pressure indicator for each pressure-lubricated gearbox.

* * * * *

15. Section 29.1309 is amended by revising paragraph (h) to read as follows:

§ 29.1309 Equipment, systems, and installations

* * * * *

(h) In showing compliance with paragraphs (a) and (b) of this section, the effects of lightning strikes on the rotorcraft must be considered.

16. Section 29.1351(d) is revised to read as follows:

§ 29.1351 General

* * * * *

(d) Operation with the normal electrical power generating system inoperative.

(1) It must be shown by analysis, tests, or both, that the rotorcraft can be operated safely in VFR conditions for a period of not less than 5 minutes, with the normal electrical power generating system (electrical power sources excluding the battery) inoperative, with critical type fuel (from the standpoint of flameout and restart capability), and with the rotorcraft initially at the maximum certificated altitude. Parts of the electrical system may remain on if—

(i) A single malfunction, including a wire bundle or junction box fire, cannot result in loss of the part turned off and the part turned on;

(ii) The parts turned on are electrically and mechanically isolated from the parts turned off; and

(iii) The electrical wire and cable insulation, and other materials, of the parts turned on are self-extinguishing when tested in accordance with § 25.1359(d) in effect on September 1, 1977.

(2) Additional requirements for Category A Rotorcraft.

(i) Unless it can be shown that the loss of the normal electrical power generating system is extremely improbable, an emergency electrical power system, independent of the normal electrical power generating system, must be provided, with sufficient capacity to power all systems necessary for continued safe flight and landing.

(ii) Failures, including junction box, control panel, or wire bundle fires, which would result in the loss of the normal and emergency systems, must be shown to be extremely improbable.

(iii) Systems necessary for immediate safety must continue to operate following the loss of the normal electrical power generating system, without the need for flight crew action.

17. Section 29.1587 is amended by redesignating (a)(6) as (a)(7), by removing ''and'' from the end of paragraph (a)(5), and by adding a new paragraph (a)(6) to read as follows:

§ 29.1587 Performance Information.

* * * * *

(a) * * *

(6) The steady gradient of climb for each weight, altitude, and temperature for which takeoff data are to be scheduled, along the takeoff path determined in the flight conditions required in § 29.67(a)(1) and (a)(2):

(i) In the flight conditions required in § 29.67(a)(1) between the end of the takeoff distance and the point at which the rotorcraft is 200 feet above the takeoff surface (or 200 feet above the lowest point of the takeoff profile for elevated heliports);

(ii) In the flight conditions required in § 29.67(a)(2) between the points at which the rotorcraft is 200 and 1000 feet above the takeoff surface (or 200 and 1000 feet above the lowest point of the takeoff profile for elevated heliports); and

* * * * *

18. Part 29 Appendix B is amended by adding a new paragraph VIII(b)(6) to read as follows:

Appendix B to Part 29—Airworthiness Criteria for Helicopter Instrument Flight

* * * * *

VIII * * *

(b) * * *

(6) In determining compliance with the requirements of § 29.1351(d)(2), the supply of electrical power to all systems necessary for flight under IFR must be included in the evaluation.

Issued in Washington, DC, on May 2, 1996.

David R. Hinson,

Administrator.

[FR Doc. 96–11493 Filed 5–9–96; 8:45 am]

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federal register

Friday
May 10, 1996

Part VII

Department of Transportation

Federal Aviation Administration

14 CFR Part 71

Proposed Modification of the Dallas/Fort Worth Class B Airspace Area, TX; Proposed Rule

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Airspace Docket No. 94–AWA–2]

Proposed Modification of the Dallas/Fort Worth Class B Airspace Area; TX

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This notice proposes to modify the Dallas/Forth Worth (DFW) Class B airspace area. Specifically, this proposal would raise the upper limit of the DFW Class B airspace area from 10,000 feet mean sea level (MSL) to 11,000 feet MSL, except in the reconfigured northern and southern sections, and would redefine several existing subareas. The FAA is proposing this rule to improve the flow of aviation traffic and enhance safety in the DFW Class B airspace area while accommodating the concerns of airspace users.

DATES: Comments must be received on or before June 24, 1996.

ADDRESSES: Send comments on the proposal in triplicate to the Federal Aviation Administration, Office of Chief Counsel, Attention: Rules Docket, AGC–200, Airspace Docket No. 94–AWA–2, 800 Independence Avenue, SW, Washington, DC 20591. The official docket may be examined in the Rules Docket, Office of the Chief Counsel, Room 916, 800 Independence Avenue, SW., Washington, DC, weekdays except Federal holidays, between 8:30 a.m. and 5:00 p.m. An informal docket may also be examined during normal business hours at the Office of the Regional Air Traffic Division.

FOR FURTHER INFORMATION CONTACT: William C. Nelson, Airspace and Rules Division, ATA–400, Office of Airspace Management, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone: (202) 267–3075.

SUPPLEMENTARY INFORMATION:

Comment Invited

Interested parties are invited to participate in this proposed rulemaking by submitting such written data, views, or arguments as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal. Communications should identify the airspace docket number and should be submitted in triplicate to the address listed above. Commenters wishing the FAA to acknowledge receipt of their comments on this notice must submit with those comments a self-addressed, stamped postcard on which the following statement is made: ''Comments to Airspace Docket No. 94–AWA–2''. The postcard will be date/time stamped and returned to the commenter. All communications received on or before the specified closing date for comments will be considered before taking action on the proposed rule. The proposal contained in this notice may be changed in light of comments received. All comments submitted will be available for examination in the Rules Docket both before and after the closing date for comments. A report summarizing each substantive public contact with FAA personnel concerned with this rulemaking will also be filed in the docket.

Availability of NPRM's

Any person may obtain a copy of this NPRM by submitting a request to the Federal Aviation Administration, Office of Air Traffic Airspace Management, 800 Independence Avenue, SW., Washington, DC 20591, or by calling (202) 267–3075. Communications must identify the notice number of this NPRM. Persons interested in being placed on a mailing list for future NPRM's should call the FAA's Office of Rulemaking, (202) 267–9677 for a copy of Advisory Circular No. 11–2A, Notice of Proposed Rulemaking Distribution System, that describes the application procedure.

Background

The Class B airspace area (formerly TCA) program was developed to reduce the potential for midair collision in the congested airspace surrounding airports with high density air traffic by providing an area wherein all aircraft are subject to certain operating rules and equipment requirements.

The density of traffic and the type of operations being conducted in the airspace surrounding major terminals increase the probability of midair collisions. In 1970, an extensive study found that the majority of midair collisions occurred between a general aviation (GA) aircraft and an air carrier or military aircraft, or another GA aircraft. The basic causal factor common to these conflicts was the mix of aircraft operating under visual flight rules (VFR) and aircraft operating under instrument flight rules (IFR). Class B airspace areas provide a method to accommodate the increasing number of IFR and VFR operations. The regulatory requirements of Class B airspace areas afford the greatest protection for the greatest number of people by giving air traffic control (ATC) increased capability to provide aircraft separation service; thereby minimizing the mix of controlled and uncontrolled aircraft. On May 21, 1970, the FAA published the Designation of Federal Airways, Controlled Airspace, and Reporting Points final rule (35 FR 7782). This rule provided for the establishment of Terminal Control Areas (TCA). To date, the FAA has established a total of 29 Class B airspace areas. The FAA is proposing to take action to modify or implement the application of these proven control areas to provide greater protection for air traffic in the airspace areas most commonly used by passenger-carrying aircraft.

The standard configuration of a Class B airspace area contains three concentric circles centered on the primary airport extending to 10, 20, and 30 nautical miles (NM), respectively. The standard vertical limits of the Class B airspace area normally should not exceed 10,000 feet MSL, with the floor established at the surface in the inner area and at levels appropriate to the containment of operations in the outer areas. Variations of these criteria may be utilized contingent on the terrain, adjacent regulatory airspace, and factors unique to the terminal area.

The coordinates for this airspace docket are based on North American Datum 83. Class B airspace areas are published in Paragraph 3000 of FAA Order 7400.9C dated August 17, 1995, and effective September 16, 1995, which is incorporated by reference in 14 CFR section 71.1. The Class B airspace area listed in this document would be published subsequently in the Order.

Related Rulemaking Actions

On June 21, 1988, the FAA published the Transponder with Automatic Altitude Reporting Capability Requirement Final Rule (53 FR 23356). This rule requires all aircraft to have an altitude encoding transponder when operating within 30 NM of any designated TCA primary airport from the surface up to 10,000 feet MSL. This rule excluded those aircraft that were not originally certificated with an engine driven electrical system, balloons, or gliders.

On October 14, 1988, the FAA published the TCA Classification and

TCA Pilot and Navigation Equipment Requirements Final Rule (53 FR 40318). This rule, in part, removed the different classifications of TCA's, and requires the pilot-in-command of a civil aircraft operating within a TCA to hold at least a private pilot certificate, except for a student pilot who has received certain documented training.

On December 17, 1991, the FAA published the Airspace Reclassification Final Rule (56 FR 65655). This rule discontinued the use of the term ''Terminal Control Area'' (TCA) and replaced it with the designation ''Class B airspace area.'' This change in terminology is reflected in this NPRM.

Pre-NPRM Public Input

In June 1992 an ad hoc committee was formed to represent all major users to analyze the DFW Class B airspace area and to develop recommendations for modifying the existing design. The ad hoc committee met regularly at various locations throughout the DFW area for approximately one year. The ad hoc committee submitted written comments on modifying the DFW Class B airspace area.

As announced in the Federal Register on October 30, 1993, (58 FR 54073) and on January 31, 1994, (59 FR 4310), pre-NPRM airspace meetings were held on December 8, 1993, in Mesquite, TX, December 13, 1993, in North Richland Hills, TX, April 5, 1994, in North Richland Hills, TX, and April 7, 1994, in Mesquite, TX. These meetings provided local airspace users with an opportunity to present input on the design of the proposed modifications of the DFW Class B airspace area. All comments received during the informal airspace meetings and the subsequent comment periods were considered and incorporated, in part, in this proposed modification. Verbal and written comments received, and the FAA's findings, are summarized below.

Analysis of Comments

Some commenters recommended that portions of the Class B airspace area be reconfigured into VFR corridors.

The FAA did not adopt this recommendation. After thorough review, it was determined that this recommended reconfiguration was not feasible. However, to accommodate the recommendation the FAA proposes to amend the airspace south of victor(V) airways, V16/94 from Class B to Class E airspace, reducing the lateral limits of the Class B airspace south of DFW Airport.

Certain commenters recommended that the Class B airspace area be decreased in size in the vicinity of Grand Prairie Airport and that prominent visual landmarks be used to assist pilots in identifying the airspace boundaries.

The FAA supports this recommended modification and proposes to modify the DFW Class B airspace area in the vicinity of Grand Prairie Municipal Airport by moving the 7 NM boundary north to follow Interstate 30 (I–30) and the 10 NM arc north to follow State Highway 303 (SH–303).

Some commenters recommended that the DFW Class B airspace area be modified near the Addison Airport (ADS) to increase traffic pattern airspace for ingress/egress to/from the ADS.

The FAA supports this recommendation and proposes to modify the DFW Class B airspace area in the vicinity of the ADS by raising the floor of the DFW Class B airspace from the surface to 2,000 feet MSL south of Lyndon Baines Johnson (LBJ) Freeway to Forest Lane, and west of ADS to Marsh Lane.

Recommendations were made to modify the DFW Class B airspace area in the vicinity of Naval Air Station Dallas (NAS Dallas) to allow for uniform transition for those aircraft operating in the airspace south of DFW Airport, and in the vicinity north of the Redbird Airport from 2,500 feet MSL to 3,500 feet MSL.

The FAA supports these recommendations, in part, and proposes to raise the floor of the DFW Class B airspace area from the surface to 2,000 feet MSL in the vicinity of NAS Dallas, and to raise the floor of the DFW Class B airspace area north of the Redbird Airport from 2,500 feet MSL to 3,000 feet MSL.

The Airline Transport Association of America (ATA) proposed raising the ceiling of the DFW Class B airspace area from 10,000 feet MSL to 11,000 feet MSL.

The FAA agrees with this recommendation and proposes to raise the ceiling of the DFW Class B airspace area, excluding that airspace overlying the V66/278 and V16/94 airways north and south of the DFW Airport to provide airspace for high performance aircraft while allowing non-participating aircraft to access certain airways above 10,000 feet MSL.

Two areas of concern surfaced relative to the airspace located between 20 and 30 NM west of DFW Airport. First, ATC, for air traffic separation purposes, sometimes assigns altitudes below the floor of this portion of the DFW Class B airspace area. Second, some commenters complained that the current floor of 5,000 feet MSL hinders VFR non-participating aircraft desiring to transit the airspace beyond 25 NM. The FAA proposes to lower the floor of the airspace from 5,000 feet MSL to 4,000 feet MSL between 20 and 23 MN west, and to raise the floor of the airspace from 5,000 feet MSL to 6,000 feet MSL between 26 and 30 MN west. This would alleviate both concerns while enhancing aviation safety and airspace utilization.

One written comment received after the December 1993 airspace meetings questioned the need for the proposed expansion of the DFW Class B airspace area northwest of the Alliance Airport.

The FAA proposes to decrease the overall amount of DFW Class B airspace area by restructuring the area northwest of Alliance Airport. While there is some proposed expansion northwest of the Alliance Airport, this proposed modification would provide a safer transition area for those aircraft operating into and out of the Alliance Airport.

The Proposal

The FAA proposes to amend 14 CFR part 71 by modifying the DFW Class B airspace area. Specifically, this proposal (depicted in the attached chart) would raise the upper limit of the DFW Class B airspace area from 10,000 feet MSL to 11,000 feet MSL, except in the reconfigured northern and southern sections, and would redefine several existing subareas. the FAA is proposing to amend the airspace south of victor airways V–16/94 from Class B to Class E airspace.

This proposal would realign the boundaries of the Class B airspace area north of Grand Prairie Municipal Airport to follow Interstate 30 (I–30) and State Highway 303 (SH–303) south of DFW. In addition, this proposed rule would raise the floor of the Class B airspace area to 2,000 feet MSL in the vicinity of NAS Dallas, south of LBJ Freeway to Forest Lane, and west of ADS to marsh Lane, and 3,000 feet MSL north of Redbird Airport. Further, the FAA proposes to lower the floor of the airspace from 5,000 feet MSL to 4,000 feet MSL between 20 and 23 NM west, and to raise the floor of the airspace from 5,000 feet MSL to 6,000 feet MSL between 26 and 30 NM west. This proposal would enhance safety and improve the flow of aviation traffic in the DFW Class B airspace area.

Regulatory Evaluation Summary

Proposed changes to Federal regulations must undergo several economic analyses. First, Executive order 12866 directs that each Federal agency shall propose or adopt a regulation only upon a reasoned

determination that the benefits of the intended regulation justify its costs. Second, the Regulatory Flexibility Act of 1980 requires agencies to analyze the economic effect of regulatory changes on small entities. Third, the Office of management and Budget directs agencies to assess the effect of regulatory changes on international trade. In conducting these analyses, the FAA has determined that the proposed rule would generate benefits that justify its costs and is not ''a significant regulatory action'' as defined in the Executive Order and the Department of Transportation Regulatory policies and Procedures. The proposal would not have a significant impact on substantial number of small entities and would not constitute a barrier to international trade. These analyses, available in the docket, are summarized below.

Costs

The FAA has determined that the proposed modification of the DFW Class B airspace area would result in little or no cost to either the agency or aircraft operators, as discussed in the following paragraphs.

The proposal would not impose any additional administrative costs on the FAA for either personnel or equipment. Projected increases in traffic volume would be absorbed by current personnel and equipment resources through more efficient services. Revising aeronautical charts to reflect the change of the airspace area would not add to the cost of the routine and periodic updating of the charts.

The proposal would not require additional avionics equipment for aircraft. Aircraft operators that currently use the affected airspace should already have Mode C transponders. In addition, aircraft operators should also have two-way radio communications. The density of air traffic in the DFW area makes it highly unlikely that VFR traffic would transit this airspace without two-way radio equipment.

Finally, the proposal should not significantly increase the cost to pilots who wish to remain clear of the proposed expanded areas of the DFW Class B airspace area. The pilots would need to make only small deviations from their current flight paths to avoid the proposed expanded areas of Class B airspace.

Benefits

The proposed rule is expected to generate benefits primarily in the form of improved traffic flow while enhancing safety. Traffic flow would improve because air traffic controllers could more efficiently handle the increasing number of operations at the DFW International Airport. Based on the FAA's Terminal Area Forecast, total aircraft operations at the DFW International Airport were about 831,000 in 1994, up from 504,000 in 1984, and are projected to increase to about 1,009,000 by the year 2000. Also, passenger enplanements were estimated to be 25.5 million in 1994, up from 15.5 million in 1984, and are projected to increase to about 35.3 million by the year 2000. The proposed rule would enhance safety by lowering the risk of midair collisions. This lower risk would result from the increased control in those areas where Class B airspace would be expanded.

The proposed rule would benefit GA aircraft operators by contracting the Class B airspace in certain areas. Additionally, it would simplify the airspace area.

Regulatory Flexibility Determination

The Regulatory Flexibility Act of 1980 (RFA) was enacted by Congress to ensure that small entities are not unnecessarily or disproportionately burdened by Federal regulations. The RFA requires a Regulatory Flexibility Analysis if a proposed rule would have ''a significant economic impact on a substantial number of small entities.'' FAA Order 2100.14A outlines the FAA's procedures and criteria for implementing the RFA. Small entities are independently owned and operated small businesses and small not-for-profit organizations. A substantial number of small entities is defined as a number that is 11 or more and which is more than one-third of the small entities subject to this proposal. The FAA has determined that the proposal would not result in a significant economic impact on a substantial number of small entities. Therefore, a regulatory flexibility analysis is not required under the terms of the RFA.

International Trade Impact Assessment

The proposal would not constitute a barrier to international trade, including the export of U.S. goods and services to foreign countries and the import of foreign goods and services to the United States. This proposal would not impose costs on aircraft operators or aircraft manufacturers in the United States or foreign countries. The modification of the Class B airspace area would only affect U.S. terminal airspace operating procedures at and in the vicinity of Dallas-Fort Worth, TX. The proposal would not have international trade ramifications because it is a domestic airspace matter that would not impose additional costs or requirements on affected entities.

Federalism Implications

This proposed rule would not have substantial direct effects on the states, the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612 (52 FR 41695; October 30, 1987), it is determined that this proposed rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

Paperwork Reduction Act

This proposed rule contains no information collection requests requiring approval of the Office of Management and Budget pursuant to the Paperwork Reduction Act (44 U.S.C. 3507 et seq.).

International Civil Aviation Organization (ICAO) and Joint Aviation Regulations (JAR)

The FAA has determined that this proposal, if adopted, would not conflict with any international agreements of the United States.

Conclusion

For reasons discussed in the preamble, and based on the findings in the Regulatory Flexibility Determination and the International Trade Impact Assessment, the FAA has determined that this regulation is not a ''significant regulatory action'' under Executive Order 12866. In addition, the FAA certifies that this regulation would not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. This regulation is not considered significant under DOT Order 2100.5, Policies and Procedures for Simplification, Analysis and Review of Regulations. A regulatory evaluation of the proposed regulation, including a Regulatory Flexibility Determination and International Trade Impact Assessment has been placed in the docket. A copy may be obtained by contacting the person identified under **FOR FURTHER INFORMATION CONTACT.**

List of Subjects In 14 CFR Part 71

Airspace, Incorporation by Reference, Navigation (Air).

The Proposed Amendment

PART 71—[AMENDED]

1. The authority citation for 14 CFR part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389; 14 CFR 11.69.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of the Federal Aviation Administration Order 7400.9C, Airspace Designations and Reporting Points, dated August 17, 1995, and effective September 16, 1995, is amended as follows:

Paragraph 3000—Subpart B—Class B Airspace

* * * * *

ASW TX B Dallas/Fort Worth, TX [Revised]

Dallas/Fort-Worth International Airport (Primary Airport)
(Lat. 32°53′49″N., long. 97°02′33″W.)
Dallas/Fort-Worth VORTAC
(Lat. 32°51′57″N., long. 97°01′41″ W.)

Boundaries

Area A. That airspace extending upward from the surface to and including 11,000 feet MSL beginning at the intersection of the DFW VORTAC 10-mile arc and Josey Lane, thence southbound on Josey Lane to Forest Lane, thence eastbound on Forest Lane until Interstate 635 (that also coincides with the DFW VORTAC 15-mile arc), extending clockwise on the DFW VORTAC 15-mile arc until the DFW VORTAC 129° radial 15-mile DME fix, thence northwest on the DFW VORTAC 129° radial until Interstate 30, extending west on Interstate 30 until the DFW VORTAC 7-mile arc, thence clockwise on the DFW VORTAC 7-mile arc until the DFW VORTAC 310° radial, 7-mile DME fix, extending northwest on the DFW VORTAC 310° radial until the DFW VORTAC 310° radial 10-mile DME fix, and extending clockwise on the DFW VORTAC 10-mile arc to the point of beginning.

Area B. That airspace extending upward from 2,000 feet MSL to and including 11,000 feet MSL beginning at the DFW VORTAC 310° radial 10-mile DME fix, thence southeast on the DFW VORTAC 310° radial until the DFW VORTAC 310° radial 7-mile DME fix, extending counterclockwise on the DFW VORTAC 7-mile arc until Interstate 30, thence eastbound on Interstate 30 to the DFW VORTAC 129° radial, thence southeast on the DFW VORTAC 129° radial until the DFW VORTAC 129° radial 10-mile DME fix, extending clockwise on the DFW VORTAC 10-mile arc until Highway 303, thence west on Highway 303 until the DFW VORTAC 10-mile DME arc, and extending clockwise on the DFW VORTAC 10-mile arc to the DFW VORTAC 300° radial 10-mile DME fix, thence northwest on the 300° radial until the DFW VORTAC 300° 13-mile DME fix, extending clockwise on the DFW VORTAC 13-mile arc until the DFW VORTAC 023° radial 13-mile DME fix, thence southeast on the DFW VORTAC 023° radial until the DFW VORTAC 023° radial 10-mile DME fix, extending counterclockwise on the DFW VORTAC 10-mile arc to the DFW VORTAC 310° 10-mile DME fix; and that airspace extending upward from 2,000 feet MSL to and including 11,000 feet MSL beginning at the intersection of the DFW VORTAC 10-mile arc and Josey Lane, thence southbound on Josey Lane to Forest Lane, thence eastbound on Forest Lane to Interstate 635, thence westbound on Interstate 635 to the DFW VORTAC 10-mile arc, and extending counterclockwise on the DFW VORTAC 10-mile arc to the point of beginning.

Area C. That airspace extending upward from 2,500 feet MSL to and including 11,000 feet MSL beginning at the intersection of the DFW VORTAC 15-mile arc and Interstate 635, extending clockwise on the DFW VORTAC 15-mile arc until the DFW VORTAC 129° radial 15-mile DME fix, thence southeast on the DFW VORTAC 129° radial until the DFW VORTAC 129° radial 20-mile DME fix, extending counterclockwise on the DFW VORTAC 20-mile arc until Interstate 635, and extending northwest along Interstate 635 to the point of beginning.

Area D. That airspace extending upward from 3,000 feet MSL to and including 11,000 feet MSL beginning at the DFW VORTAC 300° radial 10-mile DME fix, extending counterclockwise on the DFW VORTAC 10-mile arc to Highway 303, thence eastbound on Highway 303 until the DFW VORTAC 10-mile arc, extending counterclockwise on the DFW VORTAC 10-mile arc to the DFW VORTAC 129° radial, thence southeast along the DFW VORTAC 129° radial until the DFW VORTAC 129° radial 20-mile DME fix, extending clockwise on the DFW VORTAC 20-mile arc until the DFW VORTAC 217° radial, thence northeast on the DFW VORTAC 217° radial until the DFW VORTAC 217° radial 13-mile DME fix, extending clockwise along the DFW VORTAC 13-mile arc to the DFW VORTAC 300° radial 13-mile DME fix, and thence southeast on the DFW VORTAC 300° radial to the point of beginning; and that airspace extending upward from 3,000 feet MSL to and including 11,000 feet MSL beginning at the DFW VORTAC 300° radial 13-mile DME fix, thence northwest on the DFW VORTAC 300° radial until the DFW VORTAC 300° radial 20-mile DME fix, extending clockwise on the DFW VORTAC 20-mile arc until Interstate 635, extending northwest along Interstate 635 until the DFW VORTAC 10-mile arc, extending counterclockwise on the DFW VORTAC 10-mile arc until the DFW VORTAC 023° radial 10-mile DME fix, thence northeast on the DFW VORTAC 023° radial until the DFW VORTAC 023° radial 13-mile DME fix, and extending counterclockwise on the DFW VORTAC 13-mile arc to the point of beginning.

Area E. That airspace extending upward from 4,000 feet MSL to and including 11,000 feet MSL beginning at the DFW VORTAC 217° radial 20-mile DME fix, extending counterclockwise on the DFW VORTAC 20-mile arc until the DFW VORTAC 300° radial 20-mile DME fix, thence southeast on the DFW VORTAC 300° radial until the DFW VORTAC 300° radial 13-mile DME fix, extending counterclockwise on the DFW VORTAC 13-mile arc until the DFW VORTAC 217° radial 13-mile DME fix, thence southwest on the DFW VORTAC 217° radial until the DFW VORTAC 217° radial 20-mile fix, extending clockwise on the DFW VORTAC 20-mile arc until Interstate 820, thence west and north on Interstate 820 until the DFW VORTAC 23-mile arc, extending clockwise on the DFW VORTAC 23-mile arc until Highway 156, thence northeast on Highway 156 until the DFW VORTAC 329° radial, thence northwest on the DFW VORTAC 329° radial until intercepting a line defined by the DFW VORTAC 041° radial 30 DME fix and the DFW VORTAC 315° radial 30 DME fix, thence east along that line defined by the DFW VORTAC 041° radial 30 DME fix and the DFW VORTAC 315° radial 30 DME fix until the DFW VORTAC 30-mile arc, extending clockwise on the DFW VORTAC 30-mile arc until the DFW VORTAC 138° radial 30-mile DME fix, thence west until the DFW VORTAC 217° radial 28.3 mile DME fix, and thence northeast on the DFW VORTAC 217° radial until the point of beginning.

Area F. That airspace extending upward from 4,000 feet MSL to and including 10,000 feet MSL beginning at the DFW VORTAC 138° radial 30-mile DME fix, extending clockwise on the DFW VORTAC 30-mile arc until the DFW VORTAC 162° radial 30-mile DME fix, thence west until the DFW VORTAC 196° radial 30-mile DME fix, extending clockwise on the DFW VORTAC 30-mile arc until the DFW VORTAC 217° radial 30-mile DME fix, and thence northeast on the DFW VORTAC 217° radial until the DFW VORTAC 217° radial 28.3-mile DME fix, and thence east on a line to the point of beginning; and that airspace extending upward from 4,000 feet MSL to and including 10,000 feet MSL beginning at the DFW 315° radial 30-mile DME fix, extending clockwise on the DFW 30-mile arc until the DFW 336° radial 30-mile DME fix, thence east until the DFW 020° radial 30-mile DME fix, extending clockwise on the DFW 30-mile arc until the DFW 041° radial 30-mile DME fix, and thence west on a line until the point of beginning.

Area G. That airspace extending upward from 5,000 feet MSL, up to and including 11,000 feet MSL beginning at the DFW VORTAC 315° radial 30-mile DME fix, extending counterclockwise on the DFW VORTAC 30-mile arc until the DFW VORTAC 293° radial, thence southeast on the DFW VORTAC 293° radial until the DFW VORTAC 26-mile DME fix, extending counterclockwise on the DFW VORTAC 26-mile arc until Highway 377, thence southwest on Highway 377 until the DFW VORTAC 30-mile arc, and counterclockwise to the DFW VORTAC 217° radial 30-mile DME fix, thence northeast on the DFW VORTAC 217° radial until the DFW VORTAC 20-mile arc, extending clockwise on the 20-mile arc until Interstate 820, thence west and north on Interstate 820 until the DFW VORTAC 23-mile arc, thence clockwise on the DFW VORTAC 23-mile arc until Highway 156, extending northeast on Highway 156 to the DFW VORTAC 329° radial, thence northeast on the DFW VORTAC 329° radial,

until intercepting a line defined by the DFW VORTAC 041° radial 30-mile DME fix and the DFW VORTAC 315° radial 30-mile DME fix, thence west along that line until the point of beginning.

Area H. That airspace extending upward from 6,000 feet MSL to and including 11,000 feet MSL beginning at the DFW VORTAC 293° radial 30-mile DME fix, thence southeast on the DFW VORTAC 293° radial until the DFW VORTAC 293° radial 26-mile DME fix, extending counterclockwise on the DFW VORTAC 26-mile arc until Highway 377, thence southwest on Highway 377 until the DFW VORTAC 30-mile arc, and extending clockwise on the DFW VORTAC 30-mile arc until the point of beginning.

* * * * *

Issued in Washington, DC, on May 2, 1996.

Nancy B. Kalinowski,

Acting Program Director for Air Traffic Airspace Management, ATA–1.

Note: This appendix will not appear in the Code of Federal Regulations.

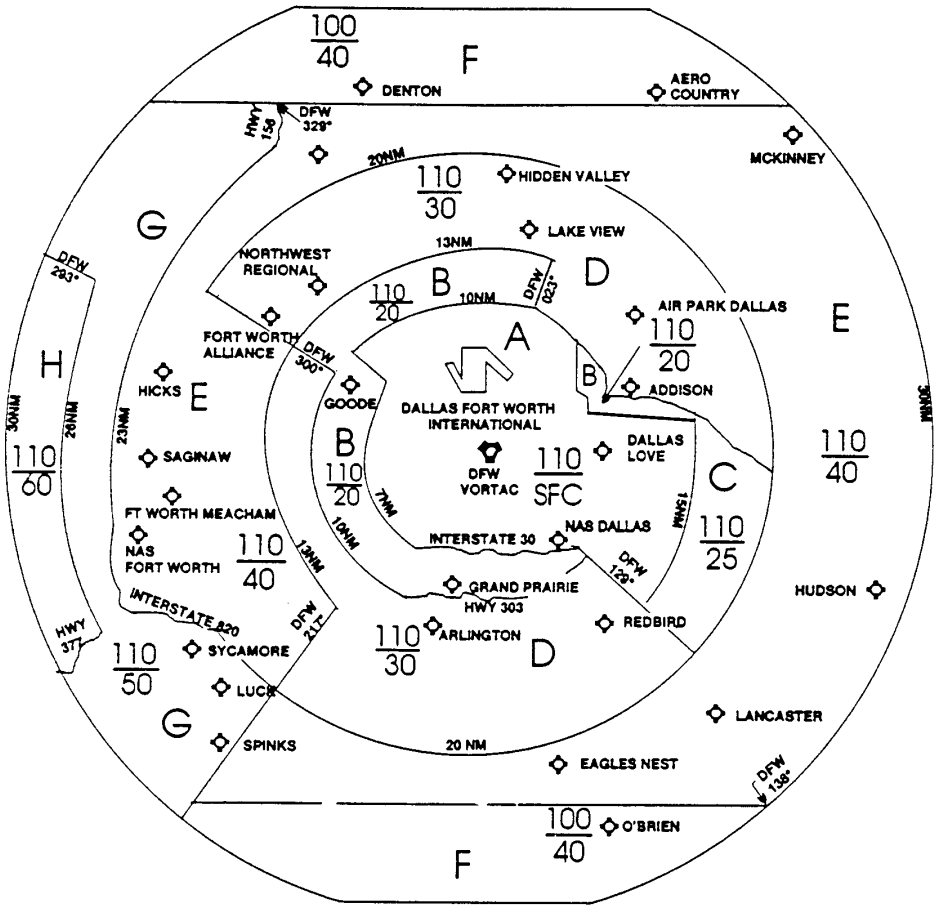
BILLING CODE 4910–13–M

Appendix—Dallas/Fort Worth International Airport Class B Airspace Area

DALLAS/FORT WORTH INTERNATIONAL AIRPORT

CLASS B AIRSPACE AREA

(NOT TO BE USED FOR NAVIGATION)



Prepared by the

FEDERAL AVIATION ADMINISTRATION

Air Traffic Publications Branch

ATP-210

[FR Doc. 96–11726 Filed 5–9–96; 8:45 am]

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federal register

Friday
May 10, 1996

Part VIII

Department of Housing and Urban Development

24 CFR Part 206

Home Equity Conversion Mortgage Insurance Demonstration: Additional Streamlining; Proposed Rule

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Part 206

[Docket No. FR–2958–P–04]

RIN 2502–AF32

Office of the Assistant Secretary for Housing—Federal Housing Commissioner; Home Equity Conversion Mortgage Insurance Demonstration: Additional Streamlining

AGENCY: Office of the Assistant Secretary for Housing-Federal Housing Commissioner, HUD.

ACTION: Proposed rule.

SUMMARY: This proposed rule would make changes to the Home Equity Conversion Mortgage (HECM) Insurance Demonstration, including technical and clarifying changes, to improve and streamline the program as a supplement to the changes made through the interim rule, published on August 16, 1995, and made final on December 21, 1995.

DATES: Comment Due Date: July 9, 1996.

ADDRESSES: Interested persons are invited to submit comments regarding this proposed rule to the Rules Docket Clerk, Office of General Counsel, Room 10276, Department of Housing and Urban Development, 451 Seventh Street, SW, Washington, DC 20410–0500.

Communications should refer to the above docket number and title. Facsimile (FAX) comments are not acceptable. A copy of each communication submitted will be available for public inspection and copying between 7:30 a.m. and 5:30 p.m. weekdays at the above address.

FOR FURTHER INFORMATION CONTACT: Richard K. Manuel, Acting Director, Single Family Development Division, Office of Insured Single Family Housing, Room number 9272, Department of Housing and Urban Development, 451 Seventh Street, SW, Washington, DC 20410, telephone (202) 708–2700; TTY (202) 708–4594. (These are not toll-free telephone numbers.)

SUPPLEMENTARY INFORMATION: The information collection requirements for the Home Equity Conversion Mortgage Insurance Demonstration have been approved by the Office of Management and Budget under the Paperwork Reduction Act of 1995, and have been assigned OMB Control Number 2528–0133. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection displays a valid control number. This rule does not contain additional information collection requirements.

Background

The Home Equity Conversion Mortgage (HECM) Insurance Demonstration was authorized by section 417 of the Housing and Community Development Act of 1987 (42 U.S.C. 5301), which amended section 255 of the National Housing Act (12 U.S.C. 1715z–20) to permit elderly homeowners to borrow against the equity in their homes. The interim rule published on August 16, 1995, at 60 FR 42754, revised 24 CFR part 206 to include improvements to the program that did not require prior public comment before implementation. The interim rule was made final on December 21, 1995, at 60 FR 66476. This proposed rule reflects additional ideas for improving the program regulations for which the Department desires public comment prior to implementation. An explanation of the proposed changes follows.

Proposed Changes to HECM Regulations

Sections 206.3 and 206.209

A definition of ''mortgage balance'' is proposed to be included that would make HECMs ''closed end'' credit for purposes of the regulations implementing the Truth in Lending Act (TILA) (15 U.S.C. 1601 *et seq.*). The rule would continue to permit prepayment by mortgagors as mandated by statute, but prepayments (including insurance or condemnation proceeds that have been applied to the debt) would be excluded from the definition of mortgage balance for purposes of calculating future loan advances, thereby prohibiting mortgagors from re-borrowing funds previously prepaid. A recent amendment to § 206.21(c) deleted specific reference to the ''open end'' credit TILA regulations at 12 CFR part 226 in anticipation of this change.

Currently, HECM funds may be prepaid and borrowed again. This fact makes the mortgage ''open end'' credit or ''revolving'' credit under the TILA. The TILA requires initial and periodic disclosures, in addition to those disclosures required by the HECM statute. The TILA disclosures have been difficult for mortgagees to produce for this type of mortgage and have increased the paperwork at closing. Mortgage lenders ordinarily only have experience with ''closed end'' credit requirements. Additionally, at this point in the demonstration, few, if any, mortgagors have utilized the option to re-borrow. HUD does not regard the option as an important aspect of the demonstration.

The definitions of ''principal limit'' and ''expected average mortgage interest rate'' in § 206.3 also would be amended to require that the principal limit grow at the mortgage interest rate plus the monthly mortgage insurance premium (MIP) rate instead of the expected average mortgage interest rate (expected rate) plus the monthly MIP rate. The expected rate would be used only when needed to project the principal limit for calculation of future payments for adjustable rate mortgages because the actual mortgage interest rate cannot be calculated in advance. HUD is particularly interested in receiving public comment on this proposal.

Under the current regulation, the principal limit increases for all purposes each month by one-twelfth of the expected rate plus the monthly MIP rate. For fixed rate mortgages, the expected rate is the same as the actual fixed interest rate that appears in the note. For adjustable rate mortgages, the expected rate is fixed at closing as the sum of the mortgagee's margin plus the weekly average yield for U.S. Treasury Securities adjusted to a constant maturity of 10 years. In contrast, the mortgage balance grows at the actual current interest rate that is applied under the note and adjusted periodically. Because two different interest rates are used to determine the principal limit and the mortgage balance on adjustable rate mortgages, these sums grow at different rates and the difference between them can become unpredictable.

When the mortgage note rate is higher than the expected rate, the mortgage balance increases at a faster pace than the principal limit. In this case the maximum loan advance amount available under a HECM line of credit is eroded by interest charged to the account balance, leaving the mortgagor with less to borrow than he or she might have anticipated. Monthly payments under a term or tenure payment option, however, are guaranteed under the loan agreement regardless of this interest rate risk.

When the note rate is lower than the expected rate, the mortgage balance grows at a slower pace than the principal limit. This discrepancy between the note rate and the expected rate creates additional potentially-available credit. This situation has caused servicing problems because mortgagors that have borrowed the full principal limit under a line of credit may at a future date have additional credit created from the difference in the interest rates.

HUD has considered several solutions to this interest rate risk problem. One solution would be to terminate a mortgagor's right to continue borrowing once his or her mortgage balance reached the principal limit, even if at a later time the interest rate differential caused the principal limit to exceed the mortgage balance. The disadvantage of this solution is that it does not address the problem of an increasing note rate resulting in an erosion of the principal limit. An alternative solution would be to cap the note rate at the expected rate. However, this solution does not address the problem presented when the note rate is below the expected rate resulting in excess credit, and is of questionable legality due to the statutory provision providing for a note rate negotiated between the mortgagor and mortgagee rather than one regulated by HUD. Another solution would be to require that all line of credit payment plans must be established together with a term or tenure monthly payment plan. Each payment plan would carry a separate principal limit. All fees and charges would be charged to the monthly payment plan balance. In this way, as long as no line of credit draws were made, the line of credit would not be effected by the interest rate fluctuations because the line of credit principal limit would be separate from the monthly payments principal limit. This solution only forestalls the problem. Once a draw is made against the line of credit the same interest rate risk problem can occur as under the current rule.

HUD does not propose these solutions because each one requires additional regulatory restraint on the terms and conditions of the HECM. Instead, HUD proposes to make a program change by altering the definitions of ''expected average mortgage interest rate'' and ''principal limit.'' The expected rate would only be used to determine future monthly payments. (Section 206.25(b)(1)(vi) provides for continued use of the expected rate to calculate future estimated interest that will accrue on scheduled monthly payments.) The monthly calculation of growth to the principal limit would not involve the expected rate but would instead be determined by using the mortgage note rate plus the monthly MIP rate. In this way, both the principal limit and the mortgage balance would grow at the same rate. This solution would give mortgagors and mortgagees more certainty in knowing what funds would be available to be drawn than the current system.

In low interest rate markets, mortgagors would not have the benefit of an increase in available principal limit. In high interest rate markets, mortgagors would not experience the erosion of lines of credit. These variations in the available principal limit would be replaced by a system with greater predictability. In the long run, the principal limit is expected to be approximately the same as the current rule because the expected rate under the current rule encompasses the market's best estimate of future note rates. This rule change would be effective only for mortgages which the mortgagee closed on or after the effective date of the final rule.

Section 206.8.

A new § 206.8 would be added to provide a first lien priority to all debt secured by the HECM, including all direct payments to the mortgagor and all other loan advances under the HECM for purposes such as interest, taxes and special assessments, premiums for hazard or mortgage insurance, servicing charges and costs of collection. Any contrary State laws would be preempted. This preemption is proposed to clarify the current uncertainty regarding the lien priority to be accorded HECM loan advances in certain circumstances and to ensure that all HECM debt will have a first lien priority. That priority is a basic assumption behind the computer model used to determine the amount of payments to the mortgagor. State law would still be applicable for determining the authority of a mortgagee to make a HECM loan as provided in § 206.9(a) of the current HECM regulation.

In the absence of an applicable Federal statute or regulation, lien priority would be determined under *United States* v. *Kimbell Foods, Inc.,* 440 U.S. 715 (1979) if the HECM had been assigned to HUD. In most circumstances courts applying *Kimbell Foods* have determined that the lien priority law of the State should be adopted as the Federal rule of decision. State law would also apply while the HECM was still held by the mortgagee as an insured mortgage.

State law is sometimes unclear regarding the appropriate priority to be given to loan advances made many years after the original mortgage was recorded when other liens have been filed in the interim. To the extent State laws are clear, they differ, and some would have the effect of subordinating the priority of HECM loan advances made after certain events such as the filing of another lien that has been brought to the attention of the HECM mortgagee. HUD or the mortgagee could guard against loss of priority to some extent by stopping further loan advances directly to the mortgagor (as permitted by the HECM loan documents when needed to protect lien priority) but this will not protect the lien priority of the mandatory loan advances that will continue for interest, mortgage insurance premiums and servicing charges. HUD or the mortgagee may find it necessary to accelerate the loan and foreclose to prevent the continued growth of debt without a first lien priority. Even without a foreclosure, the homeowner may have to move if loan advances are stopped, because of inability to pay basic homeowner expenses such as real estate taxes without further advances. This result would conflict with the program goal of non-displacement of an elderly homeowner that desires to continue living in his or her home.

The proposed rule would serve as a Federal law that courts would use to determine the lien priority of HECM loan advances. *Kimbell Foods* would be inapplicable for a HECM assigned to HUD because that decision guides courts only in the absence of a Federal law, and the regulation would otherwise preempt state law that would be applied to an insured HECM still held by a mortgagee. This use of a regulation to avoid any application of *Kimbell Foods* is in accord with *Chicago Title Ins. Co.* v. *Sherred Village Associates,* 708 F. 2d 804 (1st Cir. 1983), and preemption by regulation of state law that would otherwise apply to privately-held mortgages has been approved by the Supreme Court in cases such as *Fidelity Federal Savings and Loan Association* v. *De La Cuesta,* 458 U.S. 141 (1982) and *United States* v. *Shimer,* 367 U.S. 374 (1961).

The proposed priority lien regulation would assure that HECM loan advances made in accordance with the loan agreement would not be interrupted due to the application of State lien priority laws. Reasonable arguments can be made that, even without this rule, *Kimbell Foods* would not compel application of State lien priority laws to a HECM held by HUD due to distinctive features of the HECM program, and that State laws would not apply to a HECM held by a private mortgagee if conflict with the program goal of non-displacement, as described above, would occur. This proposed rule does not reject those arguments. It recognizes the uncertainty of current law and proposes to replace that uncertainty with a clear rule on which HUD, mortgagees and other potential lienors can rely. Private creditors intending to rely on the equity of the mortgagor in the home will be on clear notice that the

entire HECM debt will be superior to any other private lien. The proposed priority lien regulation would have one exception to permit a higher priority for state or local liens for taxes or special assessments, to the extent provided by State or local law.

Section 206.21

Paragraph (b) of § 206.21 would be amended to permit a mortgage that provides for monthly adjustments to the interest rate to be converted to one that provides for annual adjustments if the mortgage is assigned to HUD by the mortgagee. This would enable HUD to reduce greatly the servicing burden associated with ARMs that are assigned to HUD. A similar change is proposed for § 206.121(c) regarding the second mortgage held by HUD. If the mortgagee had drafted the second mortgage to provide for monthly adjustments HUD could convert it to annual adjustments.

Section 206.25

Section 206.25(d) would be revised to permit the principal limit amount set aside for a line of credit to increase at the same rate as the full principal limit whether or not combined with a term or tenure option with monthly payments. HUD has been informed that the current regulation has been interpreted to permit this by some participants in the HECM program, including the Federal National Mortgage Corporation (FNMA). Although not necessarily in conformity with HUD's original intentions behind § 206.25(d), this approach to calculating the principal limit for a line of credit has the advantage of simplicity as compared to HUD's original intention, and does not result in increased risk to the borrower or HUD. HUD is proposing a formal change in regulations to permit FNMA and others to continue with a practice that is compatible with the general design of the HECM program. Most of the actual difference in results between the various approaches to § 206.25(d) would be eliminated as a result of the separate proposal to calculate the principal limit using the actual mortgage interest rate instead of the expected average mortgage interest rate; the proposed change to § 206.25(d) is a technical revision to eliminate remaining perceived adverse effects of the current § 206.25(d). A conforming change would be made to § 206.19(c) to avoid conflicting descriptions of how line of credit payments are calculated.

Section 206.26

The specific dollar amount of $20 that mortgagees may charge when payments are recalculated would be removed from § 206.26(d), and the Secretary would be given discretion to set a fee. The Secretary would continue to set a maximum fee at $20, but would establish the amount in Handbook 4235.1 subject to future reconsideration.

Section 206.27

Changes to §§ 206.27(d), 206.117, and 206.121(c) are proposed to be made to give the Secretary the option to eliminate the HUD-held second mortgage. The current regulations require originating mortgagors to execute a second HECM security instrument and note (second mortgage) held by the Secretary. The second mortgage comes into effect only if a mortgagee defaults in making payments and is unable or unwilling to assign the mortgage to HUD. It assures that any funds advanced by HUD are secured by a mortgage. (In the case of assignments, the Secretary continues making payments to the mortgagor under the first mortgage and the second mortgage is not utilized.) HUD now concludes that it is inappropriate to bind itself by regulation to this particular approach to protection of the Secretary's financial interests.

In practice, the second mortgage has proven to be cumbersome and costly to mortgagors. First, in virtually all cases mortgagors are required to pay recording fees per page of documents recorded. Two mortgages double the recording fees. Second, mortgagees and mortgagors have mistakenly believed that the second mortgage represents additional mortgage debt and have been confused as to the purpose of the second mortgage. Third, when the mortgage has been paid off, release of the second mortgage has been time-consuming. The provisions in the legal documents regarding the relationship between the debts secured by the first and second mortgages if the second mortgage is used are complex, untested and without close precedent and therefore could invite litigation.

HUD's ultimate objective is to eliminate or reduce reliance on the second mortgage as the means of protecting the mortgagor and HUD against mortgagee defaults. The proposed changes would permit the Secretary to do without the second mortgage when deemed prudent. HUD does not expect to change its current practices, however, until it is reasonably certain that it has a legal means of enforcing an assignment of the first mortgage free and clear of any interests of other parties. At such time as legal doubts are resolved, HUD anticipates that the second mortgage requirement could be terminated without further regulatory changes.[1]

Sections 206.27 and 206.35

Currently part 206 does not permit mortgagors to hold only a life estate in the mortgaged property. At least one eligible mortgagor must hold title in fee simple or through a long-term leasehold of a fee simple interest. HUD is proposing amendment of sections 206.27(c)(1) and 206.35 to permit mortgages to be insured and remain in force even if no eligible mortgagor has any interest in the property greater than a life estate. If a mortgagor holds only a life estate when the mortgage is executed, all holders of any future interest in the property (remainder or reversion) would also be required to execute the mortgage to ensure that the mortgage was secured by a fee simple. A holder of a future interest would not execute the note or loan agreement and would not have the rights to loan proceeds of other mortgagors. The proposed change would also permit a mortgagor who held fee simple title when the mortgage was executed to subsequently convey his or her interests in the property as long as a life estate is retained.

Because the mortgage will in all cases be secured by a fee simple or long-term leasehold interest in the property, mortgagees and HUD should not be subject to any greater financial risk if the proposed change is adopted. The proposed change would recognize that an elderly homeowner may wish to convey future interests in his or her home as an estate planning measure while retaining a life interest to ensure a continued right of occupancy for the remaining lifetime. There is no conflict between this approach to estate planning and the basic objective of the HECM program—to provide elderly homeowners the financial means to continue residing in their homes for the remainder of their lifetimes. HUD has already accommodated other approaches to estate planning by

[1] Complete abandonment of a second mortgage requirement might not be prudent in the absence of a statutory change—which has not been proposed to date by HUD—that would guarantee HUD the right to assume first mortgages upon mortgagee default, similar to language found in section 306(g)(1) of the National Housing Act (12 U.S.C. 1723)(g)(1)). Section 306(g)(1) provides that the Government National Mortgage Association (GNMA) shall be subrogated fully to the rights of a defaulted issuer when GNMA makes the payment of principal and interest on securities guaranteed by GNMA. Section 306(g)(1) further provides that GNMA may provide by regulation or contract with the issuer for the extinguishment, upon default by the issuer, of any right, title or interest of the issuer in the assumed mortgages (this provision also appears in GNMA regulations at 24 CFR 390.15(b)).

permitting mortgagors to convey joint ownership of the mortgaged property to other non-elderly, non-occupant parties and by permitting a living trust to hold legal title to the home for benefit of the elderly homeowner.

Section 206.45

A new paragraph (e) would be added to § 206.45 to incorporate the free assumability regulations at 24 CFR 203.41 and 234.66 which were published in a final rule at 58 FR 42645 (August 11, 1993). Those rules codify HUD's general policy that the property mortgaged under its single family mortgage insurance programs must be freely marketable except for a limited number of specific exceptions, primarily those permissible for affordable housing purposes. While HUD does not have the same concerns about restrictions on assumptions for the HECM program as for other single family programs, because a HECM by its nature is not assumable, HUD is concerned that any property acquired by the mortgagee or HUD through foreclosure or deed-in-lieu of foreclosure needs to be readily marketable without restrictions to a wide potential market. HUD has identified one area of special impact of this policy on the HECM program for which it specifically seeks comment. The rule would prevent use of the HECM program for a unit in a condominium if the condominium association possesses a right of first refusal (unless the condominium project received written approval from HUD prior to September 10, 1993). HUD believes that there may be a substantial number of condominiums existing prior to that date that did not obtain FHA approval, have condominium associations with rights of first refusal, and have current unit owners that would be prospective applicants for a HECM. A recent proposed amendment of § 206.51 (60 FR 32630, June 23, 1995) would permit HECMs on some individual units in a condominium project that have not received HUD approval but such units would also be affected by the proposed change to § 206.45. HUD therefore also seeks comment on whether, if the proposed change to § 206.51 is adopted, HUD should insure a HECM on a unit in a condominium project that does not meet usual HUD policy regarding rights of first refusal.

Section 206.125

Paragraph (d) of § 206.125 would be amended to apply HUD's State by State time frames to define ''reasonable diligence'' as provided in 24 CFR 203.356.

Section 206.209

Section 206.209 would be revised to reflect the proposed policy that pre-payments do not increase the amount of funds available to be borrowed as discussed for § 206.3. The regulation also would provide that in the event the prepayment is made from insurance or condemnation proceeds, the principal limit would decrease by the amount of proceeds not applied to repair of the property. This will reflect the permanent reduction in the value of the security that resulted from the condemnation or unrepaired damage.

The prepayment requirements which permit the mortgagee to charge interest if the prepayment is not made within the required time frames would be eliminated. The current prepayment provision parallels the prepayment procedures for Section 203(b) mortgages. The prepayment regulation for Section 203(b) mortgages is necessary to assure that prepayments are made in a timely fashion so that interest due to GNMA security holders is available to the GNMA issuers. Since HECMs are not securitized there is no need to restrict the time of prepayment.

Other Matters

Environmental Impact

A Finding of No Significant Impact with respect to the environment has been made in accordance with HUD regulations at 24 CFR part 50, which implements section 102(2)(C) of the National Environmental Policy Act of 1969 (NEPA). This Finding of No Significant Impact is available for public inspection between 7:30 a.m. and 5:30 p.m. weekdays in the Office of the Rules Docket Clerk, Office of the General Counsel, Department of Housing and Urban Development Room 10276, 451 Seventh Street, SW, Washington, DC 20410.

Impact on Small Entities

The Secretary, in accordance with the Regulatory Flexibility Act (5 U.S.C. 605(b)), has reviewed this proposed rule before publication and by approving it certifies that this proposed rule would not have a significant economic impact on a substantial number of small entities. The proposed rule is limited to revision of the Home Equity Conversion Mortgage Demonstration. Specifically, the requirements of the proposed rule are directed to making the program more efficient for participating mortgagees, mortgagors and the Department.

Executive Order 12612, Federalism

The General Counsel, as the Designated Official under section 6(a) of Executive Order 12612, has determined that § 206.8 of the proposed rule has federalism implications. Specifically, the rule provides that State law on lien priority would be preempted if HECM loan advances made by private mortgagees would not have a first lien priority (subject only to liens for State or local taxes or special assessments). (Preemption is not an issue for loan advances made by HUD because Federal law rather than State law would apply under *United States* v. *Kimbell Foods, Inc.*, 440 U.S. 715 (1979).

The purpose of the proposed rule is to permit a mortgagee to be able to continue to make loan advances in accordance with the loan agreement (including advances for accruing interest and mortgage insurance premiums) as long as the elderly homeowner/mortgagor desires to continue to occupy his or her home, while still maintaining a first lien priority for all advances. If State law was applied and resulted in granting priority to some other lien created after the HECM was recorded, the mortgagee would need to stop further payments to the mortgagor. The mortgagee might also need to foreclose to stop the continuing accrual of items such as interest and mortgage insurance premium with a junior lien priority. Either result would conflict with the HECM program goal of preventing displacement of the elderly homeowner, either directly from foreclosure or indirectly because of lack of funds available to the homeowner for the expenses of homeownership.

This conflict itself might result in preemption of State law under relevant Supreme Court opinions. The proposed rule would remove any doubt and provide needed clarification for HUD, mortgagees, and other creditors who may rely on the mortgagor's equity. HUD has concluded that State law would ordinarily result in a first lien status for all HECM loan advances, but is concerned that applicable law is not always clear and that some situations might occur in which the application of State law would leave the first lien status in doubt. The effect of the proposed preemption is likely to be small but it is important to ensure that the HECM program remains a first mortgage program as intended by Congress.

HUD has concluded that it is not necessary to preempt laws that would give priority to liens for unpaid State or local taxes or special assessments. If the mortgagee pays them and later files an

insurance claim, HUD would reimburse the mortgagee for those amounts as part of the insurance benefits. This distinguishes these liens from other liens and there is therefore no need to object to a superior lien position. This exception permitting superior liens for unpaid taxes and special assessments means that the proposed rule would have no substantial direct effects on States or their political subdivisions, or the relationship between the Federal government and the States.

The Department believes that although the proposed rule might have federalism implications, it is designed to achieve a legitimate Federal purpose and is carefully crafted to limit its effects to those necessary to achieve that end. In these circumstances, the Department believes that the Order imposes no bar to implementation of the rule. For these reasons, the General Counsel has determined that the rule's federalism implications are not sufficiently significant to warrant preparation of a Federalism Assessment under section 6(b) of the Order.

Executive Order 12606, The Family

The General Counsel, as the Designated Official under Executive Order 12606, The Family, has determined that this proposed rule would not have potential for significant impact on family formation, maintenance, and general well-being, and, thus, is not subject to review under the order. No significant change in existing HUD policies or programs will result from promulgation of this rule, as those policies and programs relate to family concerns.

List of Subjects in 24 CFR Part 206

Aged, Condominiums, Loan programs—housing and community development, Mortgage insurance, Reporting and recordkeeping requirements.

Accordingly, 24 CFR part 206 is proposed to be amended as follows:

PART 206—HOME EQUITY CONVERSION MORTGAGE INSURANCE

1. The authority citation for part 206 continues to read as follows:

Authority: 12 U.S.C. 1715b, 1715z–20; 42 U.S.C. 3535(d).

2. Section 206.3 is amended by revising the first sentence of the definition of ''expected average mortgage interest rate,'' by revising the definition of ''principal limit,'' and by adding a new definition of ''mortgage balance,'' to read as follows:

§ 206.3 Definitions.

* * * * *

Expected average mortgage interest rate means the mortgage interest rate used to calculate future payments to the mortgagor and is established when the mortgage interest rate is established. * * *

* * * * *

Mortgage balance means the total amount of accrued debt calculated in accordance with the terms of the mortgage. For the purpose of recalculating payments under §§ 206.19(c), 206.25(b)(ii), 206.25(d) and 206.26(c), the mortgage balance includes principal that has been repaid, including insurance or condemnation proceeds that have been applied to the debt, unless the mortgage was executed before [effective date of final rule].

* * * * *

Principal limit means the maximum disbursement that could be received in any month under a mortgage, assuming that no other disbursements are made, taking into account the age of the youngest mortgagor, the mortgage interest rate, and the maximum claim amount. Mortgagors over the age of 95 will be treated as though they are 95 for purposes of calculating the principal limit. The principal limit is used to calculate payments to a mortgagor. It is calculated for the first month that a mortgage could be outstanding using factors provided by the Secretary. It increases each month thereafter at a rate equal to one-twelfth of the mortgage interest rate in effect at that time, plus one-twelfth of one-half percent per annum, unless the mortgage was executed on or after [effective date of final rule]. If the mortgage was executed before [effective date of final rule], the principal limit increases at a rate equal to the expected average mortgage interest rate plus one-twelfth of one-half percent per annum. The principal limit may decrease because of insurance or condemnation proceeds applied to the mortgage balance under § 209.209(b) of this chapter.

* * * * *

3. Subpart A is amended by adding a new § 206.8, to read as follows:

§ 206.8 Preemption.

(a) *Lien priority.* The full amount secured by the mortgage shall have the same priority over any other liens on the property as if the full amount had been disbursed on the date the initial disbursement was made, regardless of the actual date of any disbursement. The amount secured by the mortgage shall include all direct payments by the mortgagee to the mortgagor and all other loan advances permitted by the mortgage for any purpose including loan advances for interest, taxes and special assessments, premiums for hazard or mortgage insurance, servicing charges and costs of collection, regardless of when the payments or loan advances were made. The priority provided by this section shall apply notwithstanding any State constitution, law or regulation.

(b) *Second mortgage.* If the Secretary holds a second mortgage, it shall have a priority subordinate only to the first mortgage (and any senior liens permitted by paragraph (a) of this section).

4. Section 206.19 is amended to revise paragraph (c), to read as follows:

§ 206.19 Payment options.

* * * * *

(c) *Line of credit payment option.* Under the line of credit payment option, payments are made by the mortgagee to the mortgagor at times and in amounts determined by the mortgagor as long as the amounts do not exceed the payment amounts permitted by § 206.25(d).

* * * * *

5. Section 206.21 is amended to add paragraph (b)(3), to read as follows:

§ 206.21 Interest rate.

* * * * *

(b) * * *

(3) A mortgage providing for monthly adjustments to the interest rate may be converted by the Secretary to one providing for annual adjustments at any time after the mortgage is assigned to the Secretary by providing notice to the mortgagor.

* * * * *

6. Section 206.25 is amended to revise paragraph (d), to read as follows:

§ 206.25 Calculation of payments.

* * * * *

(d) *Line of credit separately or with monthly payments.* If the mortgagor has a line of credit, separately or combined with the term or tenure payment option, the principal limit is divided into an amount set aside for servicing charges under § 206.19(d), an amount equal to the line of credit (including any portion of the principal limit set aside for repairs or property charges under § 206.19(d)), and the remaining amount of the principal limit (if any). The line of credit amount increases at the same rate as the total principal limit increases under § 206.3. A payment under the line of credit may not exceed the difference between the current amount of the principal limit for the line of credit and the portion of the mortgage balance, including accrued interest and MIP,

attributable to draws on the line of credit.

* * * * *

7. Section 206.26 is amended to revise paragraph (d), to read as follows:

§ 206.26 Change in payment option.

* * * * *

(d) *Fee for change in payment.* The mortgagee may charge a fee, not to exceed an amount determined by the Secretary, whenever payments are recalculated.

* * * * *

8. Section 206.27 is amended to revise paragraphs (c)(1) and (d), to read as follows:

§ 206.27 Mortgage provisions.

* * * * *

(c) * * *

(1) The mortgage shall state that the mortgage balance will be due and payable in full if

(i) A mortgagor dies and the property is not the principal residence of at least one surviving mortgagor, or

(ii) A mortgagor conveys all or his or her title in the property and no other mortgagor retains title to the property. For purposes of the preceding sentence, a mortgagor retains title in the property if the mortgagor continues to hold title to any part of the property in fee simple, as a leasehold interest as set forth in § 206.45(a), or as a life estate.

* * * * *

(d) *Second mortgage to Secretary.* Unless otherwise provided by the Secretary, a second mortgage to secure any payments by the Secretary as provided in § 206.121(c) must be given to the Secretary before a Mortgage Insurance Certificate is issued for the mortgage.

* * * * *

9. Section 206.35 is amended by adding a new sentence at the end, to read as follows:

§ 206.35 Title held by mortgagor..

* * * If one or more mortgagors hold a life estate in the property, for purposes of this section only the term ''mortgagor'' shall include each holder of a future interest in the property (remainder or reversion) who has executed the mortgage.

10. Section 206.45 is amended to add a new paragraph (e), to read as follows:

§ 206.45 Eligible properties.

* * * * *

(e) *Freely marketable.* The property must be freely marketable. Conveyance of the property may only be restricted as permitted under 24 CFR 203.41 or 234.66 and this part.

11. Section 206.117 is revised to read as follows:

§ 206.117 General.

The Secretary is required by statute to take any action necessary to provide a mortgagor with funds to which the mortgagor is entitled under the mortgage and which the mortgagor does not receive because of the default of the mortgagee. The Secretary may hold a second mortgage to secure repayment by the mortgagor under § 206.27(d) or may accept assignment of the first mortgage.

12. Section 206.121 is amended by revising the first two sentences of paragraph (c), to read as follows:

§ 206.121 Secretary authorized to make payments.

* * * * *

(c) *Second mortgage.* If the contract of insurance is terminated as provided in § 206.133(c), all payments to the mortgagor by the Secretary will be secured by the second mortgage, if any. Payments will be due and payable in the same manner as under the insured first mortgage, except that if the first mortgage provided for monthly adjustments to the interest rate under § 206.21(b)(2) then the Secretary may convert the second mortgage to an annually adjustable interest rate under § 206.21(b)(1) at any time by providing notice to the mortgagor. * * *

13. Section 206.125 is amended to revise paragraph (d)(3), to read as follows:

§ 206.125 Acquisition and sale of the property.

* * * * *

(d) * * *

(3) The mortgagee must give written notice to the Secretary within 30 days after the initiation of foreclosure proceedings, and must exercise reasonable diligence in prosecuting the foreclosure proceedings to completion and in acquiring title to and possession of the property. A time frame that is determined by the Secretary to constitute ''reasonable diligence'' for each State is made available to mortgagees.

* * * * *

14. Section 206.209 is revised to read as follows:

§ 206.209 Prepayment.

(a) *No charge or penalty.* The mortgagor may prepay a mortgage in full or in part without charge or penalty at any time, regardless of any limitations on prepayment stated in a mortgage. Amounts prepaid are not available to be re-borrowed, unless the mortgage was executed before [effective date of final rule].

(b) *Insurance and condemnation proceeds.* If insurance or condemnation proceeds are paid to the mortgagee, the principal limit and the mortgage balance shall be reduced by the amount of the proceeds not applied to restoration or repair of the damaged property.

Dated: April 12, 1996.

Nicolas P. Retsinas,

Assistant Secretary for Housing-Federal Housing Commissioner.

[FR Doc. 96–11649 Filed 5–9–96; 8:45 am]

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federal register

Friday
May 10, 1996

Part IX

Department of Commerce

National Oceanic and Atmospheric Administration

15 CFR Part 902
50 CFR Parts 216 and 222
Reporting and Recordkeeping Requirements; Final Rule

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

15 CFR Part 902

50 CFR Parts 216 and 222

[Docket No. 960419116–6116–01; I.D. 122492C]

RIN 0648–AD11

Marine Mammal Special Exception Permits to Take, Import and Export Marine Mammals; Update of Office of Management and Budget (OMB) Approval Numbers

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Final rule.

SUMMARY: This final rule updates and consolidates the regulations for special exception permits to: Take, import, export, or carry out any other otherwise prohibited act involving marine mammals for the purposes of scientific research, enhancing the survival or recovery of a marine mammal species or stock (enhancement), educational and commercial photography, and public display under the Marine Mammal Protection Act of 1972 (MMPA); take, import, export or carry out any other otherwise prohibited act concerning endangered or threatened marine mammals for scientific purposes or enhancement under the Endangered Species Act of 1973 (ESA); and, determine the status and disposition of rehabilitated stranded marine mammals. This rule sets forth revised procedures for these permits in order to make administration of the NMFS marine mammal permit program more efficient, consistent, and predictable.

This rule also updates OMB Paperwork Reduction Act approval numbers for applications and reports for special exception permits.

EFFECTIVE DATE: This final rule is effective June 10, 1996.

ADDRESSES: National Marine Fisheries Service, (F/PR1), 1315 East-West Highway, Silver Spring, MD 20910.

FOR FURTHER INFORMATION CONTACT: Laurel Bryant or Ann Terbush, Permits Division, Office of Protected Resources, 301/713–2289.

SUPPLEMENTARY INFORMATION:

Purpose

A proposed rule was published (58 FR 53320, October 14, 1993) to consolidate into a single set of regulations all permitting requirements under the MMPA, the ESA, and the Fur Seal Act (FSA) to take, import, or export all protected species under the NMFS jurisdiction for purposes of scientific research or enhancement, and public display, and to provide clear procedures for the disposition of rehabilitated stranded marine mammals.

In contrast, this final rule implements only a part of that proposed rule; namely, it establishes basic permit requirements applicable to all permits to take, import and export marine mammals and marine mammal parts for purposes of scientific research and enhancement, photography, and public display (for captures and initial imports) under the MMPA; provides additional permit criteria specific to scientific research and enhancement only; and establishes clarified administrative procedures for determining the releasability or non-releasability of rehabilitated stranded marine mammals and their disposition.

Scope

This notice responds to the comments and the final rule incorporates a number of the changes recommended by commenters. In addition, the rule implements certain statutory changes made to the MMPA by the MMPA Amendments of 1994 (1994 Amendments) (Public Law 103–238) enacted on April 30, 1994.

Photography and public display. Not included in this final rule are the additional requirements specific to photography or public display established by the 1994 Amendments. The 1994 Amendments included significant changes regarding these activities. Accordingly, NMFS will publish separate proposed rules for public comment for these areas.

ESA species. It is important to note that this final rule applies to the issuance of special exception permits under both the MMPA and ESA for species of marine mammals only. However, activities involving species other than marine mammals that are protected under the ESA will continue to require a permit issued under separate ESA regulations.

History

The 1993 proposed rule. The proposed rule proposed to amend and consolidate permit regulations under the FSA, MMPA and the ESA to facilitate ''one-stop shopping'' for the issuance of permits to take ''protected species'' (including species that are depleted under the MMPA, and threatened and endangered under the ESA) for purposes of scientific research, enhancement and public display. The proposed rule was also designed to establish permit conditions capable of addressing the various circumstances that had evolved over two decades of issuing permits to take marine mammals. For example, although photography of marine mammals in the wild is a common source of research and educational information, the MMPA did not provide an exception for such an activity. The 1993 proposed rule attempted to facilitate research related photography under statutory provisions for bona fide scientific research and enhancement activities, while at the same time guarding against the use of research permits for commercial activities, which had become a growing concern. However, comments received on the proposed rule were critical of these provisions as being too restrictive and bureaucratic. The new authority to issue permits for educational and commercial photography provided by the 1994 Amendments eliminates the need for addressing photography in much detail under scientific research permits.

The proposed rule was originally open for public comment for a 60-day period. A number of focused briefings on the proposed rule were held for a variety of interested parties, including Congress, various groups directly affected by the regulations, and the public. In addition, NMFS held three regional public hearings: Silver Spring, MD on December 3; Oakland, CA on December 6; and Chicago, IL on December 8. A combined total of 53 oral and written testimonies was submitted for the record through the public hearing process. Due to the level of interest expressed, NMFS extended the public comment period for an additional 30 days, closing on January 28, 1994. In addition, a transcribed question and answer session was held with certain representatives of the public display industry at their request. A total of 187 comments were received from individuals and organizations representing the scientific research community, public display industry, and conservation and animal protection interests. A discussion of and response to those comments is detailed below.

The 1994 Amendments. The 1994 Amendments substantially revised the MMPA. The statutory changes to the MMPA that impact this final rule include: Statutorily defining the term harassment; providing a General Authorization for bona fide research involving only Level B harassment; waiving the public comment process for research permits to be issued under emergency situations; eliminating the

statutory restriction against duplication of scientific research projects; statutorily providing for the issuance of permits for purposes of educational and commercial photography; and substantial changes to the public display provisions of the Act, eliminating the basis for many of the provisions that had been included in the proposed rule.

Response to 1993 Comments and Discussion of 1994 Amendments. Many commenters found the scope and organization of the proposed rule to be confusing, arguing that they had difficulty determining which regulations applied to their expressed interest.

Organization. In the proposed rule, each regulatory section was subdivided into four categories: General (i.e., basic requirements applicable to all permits), Public display, Scientific research, and Enhancement. This required a reviewer to identify within each section, both the basic permit requirements and the requirements particular to their area of interest.

In response, these final regulations have been significantly reorganized by removing non-statutory general conditions and reporting requirements from regulatory text; listing requirements basic to all permits in §§ 216.33 through 216.40 (i.e., application procedures, issuance criteria, permit restrictions, conditions, reporting requirements, amendment procedures, and penalties); and providing the additional requirements applicable to each special exception purpose in separately identified sections (i.e., § 216.41 contains the additional requirements for Scientific Research). The table of contents has been revised to include identification of sections reserved for future photography and public display regulations.

A number of comments questioned why the proposed rule would amend the Pribilof Islands and northern fur seal regulations issued under the FSA (part 215). These regulations were included to reduce regulatory burden and confusion by consolidating, under the MMPA, the requirements contained under the FSA regarding the take, transportation, importation, exportation or possession of fur seals or their parts for educational, scientific or exhibition purposes. However, these changes to part 215 were included in the interim final rule for the General Authorization for bona fide scientific research (59 FR 50372 October 3, 1994) and are, therefore, not included with this final rule.

Disruption as a part of harassment. The proposed definition of harass drew general criticism over its inclusion of the term disruption. Commenters argued that, combined with the 1993 proposed appendix of approach guidelines and reporting requirements, inclusion of the term would create too much bureaucratic burden, over-reporting of takes, and stifle scientific research. Commenters also expressed concern that NMFS would not enforce the moratorium on taking against someone unintentionally harassing a marine mammal. Members of the public disrupting sea lions hauled-out at a public wharf were cited as an example. Although commenters did not believe NMFS would institute enforcement actions for such incidents of unintentional harassment, or that it was the intent of Congress to focus on such incidents, they were concerned that NMFS might impose a higher standard on researchers. The 1994 Amendments defined harassment, and it is that definition that is included in this rule (see § 216.3 Definitions).

Approach guidelines (Appendix B). In view of the statutory changes defining harassment, and in response to the comments, NMFS has eliminated the Appendix B listing of approach guidelines and will instead refer applicants to the appropriate regional office(s) to receive any approach guidelines developed for the species of marine mammals specific to that region.

Reporting. Comments were generally critical of the reporting requirements regarding scientific research, arguing that the detail requested on behavioral responses was excessive, and the amount of data requested could compromise a researcher's ''stock-in-trade'' by forcing public documentation of data and information before it could be synthesized into published material.

In conjunction with the previous discussion, NMFS points out that a recurring theme throughout the history of issuing permits for the harassment of marine mammals has been the need for objective standards for identifying stressful responses in marine mammals to activities and closeness of approach which harass them. Such standards would prove valuable in facilitating better management practices in the wild and controlling against activities which may be detrimental to individual marine mammals or their stocks. In an effort to maintain this aspect of the reporting requirements while at the same time easing burdens, the reporting requirements have been made more flexible by emphasizing summaries of information and researcher discretion for determining ''noteworthy'' behavioral responses.

General take category. Many comments expressed support for a general take category allowing for routine, non-invasive harassment for purposes of scientific research, photography and whale watching.

The 1994 Amendments defined harassment and divided such takes into two levels of impact: Level A harassment has the potential to injure, and Level B harassment has only the potential to disturb (§ 216.3 Definitions). Bona fide scientific research projects which do not exceed Level B harassment on species not listed under the ESA are eligible for authorization under the new General Authorization category. This authorization is a streamlined process without public comment for low levels of harassment (Level B). A final rule based on comments received on the interim final rule (59 FR 50372. October 3, 1994) implementing the General Authorization now in effect, will be published separately in the Federal Register. The new permit category to harass marine mammals in the wild for purposes of educational and commercial photography also will allow only Level B harassment. A proposed rule for photography permits will be published in the Federal Register at a later date.

With regard to whale watching, there is no statutory exception provided for observational cruise activities, however, such activities can be conducted carefully without harassing marine mammals. Therefore, NMFS will continue to inform prospective vessel operators of guidelines to follow in an effort to avoid harassment.

Fees. A great deal of controversy was generated by NMFS' proposal to increase the fees for processing permits. Comments ranged from perceiving these fees as intentionally punitive against various permitted activities, to detailed suggestions for tiering the fees based on the type of permit, the level of staff review involved, and the financial disposition of the applicant.

In view of the significant changes made to the public display provisions of the statute, the nominal fees associated with scientific research, and a complete absence of any likely consensus on the subject of scientific research fees, NMFS has eliminated the proposed fee structure. This issue may be reconsidered at some time in the future. In the interim, no fee will be charged for these special exception permits.

Ethics of captivity. Many comments discussed the ethics of captivity, questioning the practice of holding marine mammals for public display and suggesting that a ban be placed on all captivity.

Since the passage of the MMPA in 1972, Congress has recognized the

public display of marine mammals as an exception to the moratorium on taking. Congress continued to recognize public display in the 1994 Amendments by continuing to provide for this activity in statute, and increasing significantly the authority and discretion of the public display industry over the marine mammals they hold.

Appendix A and C. As proposed in 1993, an Appendix A was provided for listing the activities that would require a special exception permit. In addition, an Appendix C provided the application information anticipated for special exception permits. Due to the controversy generated by the proposed scale of fees and the corresponding activities listed in Appendix A, NMFS has eliminated Appendix A. NMFS has also eliminated Appendix C and on request will provide application instructions for each permit category.

Bona fide scientific research (§ 216.3). A number of comments were critical of the proposed definition of bona fide scientific research, arguing that it extended unlimited discretion to NMFS for determining what was bona fide. The definition in the 1994 Amendments closely parallels the definition in the proposed rule. In practice, NMFS expects that the definition provides flexibility to an applicant rather than unlimited discretion to the agency.

Custody (§ 216.3). In response to comments on the proposed definition, and in consideration of the extensive changes to the public display provisions by the 1994 Amendments, the definition of custody has been simplified.

Humane (§ 216.3). Several comments were critical of the proposed definition of humane, arguing that the definitions utilized by the National Institutes of Health or American Veterinary Medicine Association should be adopted instead. In response, NMFS points out that the definition is essentially identical to the definition in the statute.

Interactive program (§ 216.3). A number of comments expressed a range of concerns over the definition of interactive program. Some commenters stated that NMFS had no authority over these activities, while others urged the elimination of therapeutic swim programs due to lack of bona fide scientific research criteria. The 1994 Amendments eliminated MMPA's jurisdiction over these public display captive care and maintenance issues, eliminating the need to define interactive program.

Public display (§ 216.3). A number of comments criticized the proposed definition of public display for being at odds with the MMPA and in violation of First Amendment rights by including the requirement for educational and conservation programs as part of the definition. It was suggested that the proposed definition parallel that contained in statute.

There is no definition of public display contained in the statute. Rather, prior to the 1994 Amendments, public display was referred to in the context of issuing a permit for public display to an applicant which offers a program for education or conservation purposes that, based on professionally recognized standards of the public display community, is acceptable to the Secretary of Commerce (Secretary). In keeping with this reference, NMFS included in the proposed rule reference of these programs as part of the definition.

The 1994 Amendments eliminated the requirement that public display education and conservation programs be acceptable to the Secretary. Public display education and conservation programs are now only subject to self-regulation. Accordingly, reference to education and conservation programs has been eliminated from the definition.

Initial review process (§ 216.33(c)). A number of comments were critical of the initial review process, arguing that it provided NMFS an opportunity to reject a permit application before receiving the benefit of public comment. The purpose of the initial review is to ensure that an application is appropriate, valid, and complete prior to its publication for public review. Premature publication without benefit of such determination could expose the applicant and agency to unnecessary administrative burdens, delays, and public confusion.

Adequate EA/EIS information (§ 216.33(c)). Several comments expressed confusion over the requirement that an applicant submit sufficient information to enable NMFS to determine whether the proposed activity will be categorically excluded from further environmental documentation under the National Environmental Policy Act of 1969 (NEPA).

NEPA applies to federally approved, initiated, or funded activities that impact the human environment. As such, it is necessary to retain this requirement of applicants in order to comply with NEPA. In an effort to provide regulatory ''one-stop-shopping'', NMFS is making every effort to include up front all requirements and provisions mandated by statute. Compliance with NEPA is a critical component of that process. As in the past, NMFS will make every effort to assist an applicant with NEPA compliance. Nevertheless, it is the responsibility of the applicant to consider the potential impacts of its proposed activity and provide the necessary information accordingly.

Marine Mammal Commission's (MMC) failure to comment (§ 216.33(d)). Many comments were critical of the provision which would regard the MMC's failure to comment on an application as a recommendation to deny the permit. It was suggested that the failure to comment by the MMC should be regarded as a recommendation to issue, and that recommendations to deny a permit be available for review by the applicant.

NMFS believes it would be inappropriate to default a no-comment to a recommendation status. However, in the same vein, NMFS recognizes the unfairness of defaulting to a denial status. In response, the recommendation to deny has been replaced with ''no objection to issuance'' (§ 216.33(d)(2)). With regard to comments received from the MMC on permit applications, these are a matter of public record and have always been available to anyone interested in reviewing them.

Duplication. Several comments criticized proposed language controlling against unnecessary duplication of scientific research projects, pointing out that duplication is an important aspect of investigating the soundness of a hypothesis. This language was a direct implementation of statutory language which specified scientific research to ''not involve unnecessary duplication of research.''

The 1994 Amendments struck from the statute the language restricting unnecessary duplication. Therefore, duplication is no longer a regulatory matter except as it relates to whether a proposed activity is bona fide scientific research, and the need to monitor against the cumulative impact of activities with the potential to exceed Level B harassment (§ 216.34(a)(4)).

Notarized copy (§ 216.35(j)). A number of comments were critical over the requirement that an original or notarized copy of the special exception permit be in the possession of the permit holder during the time of the authorized special exception activity. This provision was argued as unnecessary and too restrictive. In reconsidering the value of this provision for purposes of enforcement against fraud, NMFS has determined that an original or a copy of an original will satisfy the intent behind this requirement and has revised the provision accordingly.

Import and export (§ 216.37). A number of comments were critical of the

provisions for regulating the import and export of marine mammal parts for scientific research, claiming that they were too bureaucratic and would stifle activities such as research and education. In addition, there was concern expressed over lost research opportunities and information due to the prohibition against importing marine mammal parts which resulted from a lethal activity otherwise prohibited under the Act (§ 216.41(c)(1)(v)).

As originally mandated in 1972, the restriction against the import and export of marine mammal parts was designed to prevent the development of commercial markets for marine mammal parts or products derived therefrom. However, the circumstances of bona fide scientific research involving import and export of marine mammal parts are varied, making clarity in regulations difficult. In addition, previously only the export of ESA listed species and parts was prohibited. The 1994 Amendments extended this prohibition to all marine mammals and marine mammal parts, except for the export of living marine mammals for purposes of public display.

In response, NMFS has made every effort to implement the intent of the law without creating undue burden against scientific research activities by ensuring that adequate documentation is provided for a part's acquisition, location and possession. Flexibility has also been provided at the sole discretion of the Office Director regarding importation of parts for bona fide scientific research that may have resulted from prohibited activities. For example, as a general rule it is illegal to import parts that have been taken in violation of domestic and foreign law. However, acknowledging the research value of some of these parts, the Office Director may authorize their importation for bona fide scientific research purposes.

Major and minor amendments (§ 216.39). Some confusion was expressed over the need to maintain a distinction between major and minor amendments, suggesting that all amendments be treated as major amendments, thereby reducing the confusion over the two terms. In response, NMFS believes that not all amendments should be required to go through a public review process, and that only those amendments that change elements of a permit which are statutorily highlighted as fundamental permit terms and conditions should be subject to public review (i.e., changes in: the number and species of marine mammals affected; the manner in which they are taken; the location; and the period of time the permit is valid). Other changes (i.e., minor amendments) are most appropriately addressed on a case-by-case basis between the permit holder and the Office Director without additional opportunity for public comment. Consistent with this policy, comments received, and in keeping with current administration of the program, the process for a hearing on a minor amendment as outlined in the proposed rule has been eliminated from this rule.

Lethal take as critically important (§ 216.41(b)(2)). Several commenters criticized the use of the phrase ''critically important research need'' as being too ambiguous a requirement for research results involving lethal take. In response, NMFS notes that this language is taken directly from the statute, which remains unchanged by the 1994 Amendments.

Publication of research results (§ 216.41(c)(1)(ii)). A number of commenters expressed concern over the requirement that research results be published within a ''reasonable period of time'', questioning what the agency would define as reasonable. In response, it would be arbitrary and impractical to define in advance what would constitute a reasonable period of time applicable to all circumstances. As such, NMFS has retained this requirement as a necessary characteristic of bona fide scientific research and would argue that by not defining what is reasonable the regulations provide adequate flexibility and deference to the researcher. In addition, Congress also recognized publication and availability of research results as necessary characteristics of bona fide scientific research by including these parameters in the new statutory definition of bona fide research (§ 216.3).

Personnel experience and direct supervision (§§ 216.35(f)–(g) and 216.41(c)). A number of comments expressed criticism of the requirements that all personnel conducting permitted activities under the authority of a scientific research permit must be directly supportive of and necessary for the permitted research activity. It was argued that this was a matter of internal personnel management and not an issue of regulatory concern. In addition, several commenters argued against the requirement that activities be conducted under the direct supervision of the principal investigator or a co-investigator, finding this to be too restrictive.

In response, permits are issued based in significant part on the determination that the proposed activity is to be conducted by qualified individuals capable of accomplishing the activity, in this case bona fide scientific research. Much of that determination is necessarily based on the qualifications of the applicant, principal investigator (PI), co-investigator(s) and any supportive personnel listed to conduct work under the terms of the permit. As such, NMFS has retained this language and would note that discretion over personnel matters is left entirely to the applicant.

Direct supervision over permitted activities by the PI or a co-investigator has been retained by NMFS as a necessary requirement (§ 216.41(c)(1)(iii)). In the past, inexperienced personnel have conducted permitted activities involving the take, import or export of marine mammals without direct supervision and left a project vulnerable to criticism and litigation.

It is important and reasonable to presume that the PI or a co-investigator will be directly involved in the activity authorized under a permit. However, this requirement should in no way be construed as a ''draconian effort'' to force critical research personnel to supervise the most routine of functions. Rather, it is intended to ensure the integrity of a bona fide research permit and the activities it has authorized. Qualified individuals may be designated in the permit as co-investigators to conduct, or directly supervise the conduct of, the taking, import and export activities authorized under a permit, but the PI is ultimately responsible for all such activities. To ensure that the roles and responsibilities of the PI and co-investigator(s) are clearly understood, definitions for both of these terms have been added (see § 216.3).

Prohibiting public display of marine mammals held for research (§ 216.41(c)(1)(vi)). A number of comments expressed concern over restricting the public display of marine mammals held for scientific research. Some comments identified specific instances in which research facilities display their marine mammals as a means of educating the public about the research and receiving donations for financial support of research projects.

As scientific research and public display are recognized by statute as two separate activities, NMFS has retained this restriction as a necessary distinction between these activities. However, in response to concerns over the public viewing of marine mammals involved with research projects, the regulatory exceptions to this restriction clearly provide adequate flexibility to

allow such activities, under appropriate conditions, to occur under a scientific research permit.

Marketable products (§ 216.41(c)(1)(vii)). One of the more contentious areas of comment was the prohibition against the commercial sale of products derived from activities conducted under a scientific research permit. Concern was primarily expressed by commercial entities specializing in photographic coverage of research. In addition, many criticized the proposed definition of marketable product as beyond the jurisdiction of NMFS.

The proposed rule was in part driven by increasing reports and concerns about abuse of the scientific research permit system for commercial purposes. Although NMFS recognized the educational and scientific value of photographic coverage of marine mammals in conjunction with research, scientific research permits had, in some instances, been exploited for commercial purposes.

The 1994 Amendments acknowledged the need to provide for photographic activities in a controlled manner by permitting low levels of harassment of marine mammals for the purposes of commercial and educational photography. This new provision eliminated the need for much of the restrictive language included in the proposed rule for scientific research as well as for the need to define marketable product.

Permit conditions and reporting requirements. The regulatory text establishes permit-specific conditions and restrictions. By contrast, non-statutory general permit conditions and reporting requirements have been eliminated from the regulatory text. As a general rule, these general conditions and reporting requirements tend to vary given the nature of the permitted activity. Elimination of the permit conditions and reporting requirements provides NMFS with greater flexibility, allowing it to incorporate only those conditions and requirements that are appropriate to the permit. Appropriate general conditions and reporting requirements will be incorporated into the permit itself, and must be adhered to along with all other terms and conditions.

Most of the general conditions and reporting requirements that may be incorporated into a permit issued under this subpart, appear below. Additionally, these conditions and requirements may also be obtained from NMFS upon request (see **ADDRESSES**).

Conditions and Reporting Requirements for All Permits

Conditions

1. The permit holder shall provide the Director (Regional Director) written notice of the date, time, and port at least one week in advance of any import or export, unless this notice is waived by the Regional Director in writing in advance.

2. The permit holder shall not, in interstate or foreign commerce, deliver, receive, carry, transport, ship, purchase, or sell, or attempt any of the same, any threatened or endangered marine mammal species acquired under this subpart except with the prior approval of the Office Director and subject to any conditions the Office Director may prescribe.

3. Upon request by the Office Director, the permit holder shall allow any employee of NOAA or any other person designated by the Office Director to inspect or observe the permit holder's records, facilities, marine mammals, marine mammal parts, and activities, and shall provide all additional information related to any inspection.

4. If activities authorized under a special exception permit have adverse unforeseen effects on the ecosystem of which marine mammals are a part, the permit holder must suspend permitted activities and notify the Regional Director, and, if marine mammals are involved, the Office Director, of the circumstances and any relevant observations and recommendations. The permit holder shall not continue such permitted activities until specifically authorized by the Regional Director or, if marine mammals are involved, the Office Director.

5. The Permit holder must immediately cease all permitted activities if so required by the Office Director on the basis of new information that demonstrates that the permitted activities may have an adverse effect on individual marine mammals, on the species or stock, or on the marine ecosystem, that was not anticipated at the time of permit issuance. Permitted activities may be resumed by the permit holder only upon specific authorization by the Office Director, and subject to any terms or conditions that the Office Director determines necessary, consistent with the provisions of 216.35.

6. The permit holder shall participate in a cooperative endangered and threatened marine mammal breeding program if requested by the Office Director.

7. When animal-specific information for live import or capture is not available at the time of permit issuance, the permit holder must request authorization by the Office Director prior to importing or initiating a capture activity for long-term or permanent captive maintenance (i.e., other than short-term capture and release) of a living marine mammal. The permit holder must:

i. Request authorization to import or capture at least 30 days prior to the proposed importation or capture date;

ii. Provide the proposed dates and, for imports, country of origin, port of entry, description of the marine mammals to be imported, and, for captures, the location of the capture and associated taking;

iii. Identify the proposed method, including, but not limited to, a detailed description of the containers/devices to be used and any special care required, modes (i.e., aircraft, truck, other), duration (including any transfer points), and date of transport, and the attending veterinarian, or authorized support personnel of the permit holder knowledgeable in the area of marine mammal care for the species concerned, who will accompany the marine mammal; and

iv. Provide a license and or registration issued by the Animal and Plant Health Inspection Service; a certification, to the satisfaction of the Office Director, that all applicable standards under the Animal Welfare Act will be complied with, and that any violations of those standards have been resolved and any required corrective actions taken, or will be within a period specified by the Office Director; and a certification from the responsible veterinarian that the transport will be conducted in compliance with the applicable standards of the Animal Welfare Act.

Reporting

1. *Annual reports.* All permit holders shall file written annual reports with the Office Director. Annual reports shall provide information requested by the Office Director, and shall be filed on the date set forth in the permit. At the discretion of the Office Director, the reporting deadline may coincide with the end of the permit holder's fiscal year or research season.

2. *Special reports.* Special reports include but are not limited to:

a. *Live captures.* Where the permit authorizes a capture from the wild, the permit holder shall submit a written live capture report to the Office Director within 30 days of capture. The report shall set forth the time and specific location (i.e., latitude/longitude) of the capture, the number of marine mammals chased or detained incidental to

capture, and any deaths, injuries or complications that arose in connection with capture. For each marine mammal listed, the report must set forth the animal's size, age, sex, and reproductive condition.

b. *Lethal take.* Where a lethal take is authorized under the permit, the permit holder shall submit a written report to the Office Director within 30 days of the authorized lethal take. Where an actual or presumed lethal take occurs inadvertent or incidental to permitted activities, the permit holder shall notify the Office Director within 12 hours of the lethal take, or within 12 hours of return to port if the taking occurred at sea. This lethal take report or notification, as applicable, shall set forth the date, time, location, number, and, to the extent possible, age/size, sex, and reproductive condition of each animal killed. For inadvertent or incidental mortalities, notification shall also include the circumstances accompanying the incident and all actions taken to reduce the potential for future occurrences. A necropsy must be conducted and a report submitted if required by the Office Director.

c. *Initial importation of marine mammal parts.* Within 30 days of the initial importation of any marine mammal part, the permit holder shall submit a written report to the Office Director. The report shall include a description of the part and the unique number assigned to the part.

d. *Transfer, export or re-importation of marine mammal parts.* The permit holder shall provide written notification to the Regional Director within 30 days after any transfer, export, or re-import of a marine mammal part. Notification shall include: A description of the part and unique number; the person to whom the part was transferred, exported or reimported and, if applicable, the recipient's permit number; the purpose of the transfer, export or reimport; and, for transfers, certification that the recipient has agreed to comply with the requirements of § 216.37(a) for subsequent transfers.

e. *Other.* If the permit holder observes an unexpected event that may pose a significant adverse affect upon the health or welfare of a living marine mammal species subject to the permit, or the marine ecosystem of which they are a part, the permit holder shall submit a brief written report to the Office Director describing the circumstances concerned and all relevant observations or recommendations.

Additional Scientific Research and Enhancement Conditions and Reporting Requirements

Conditions

In addition to those conditions detailed above, scientific research and enhancement permits are subject to the following conditions:

1. Unless approved by the Office Director, the PI and co-investigators identified in the permit shall not be changed. A request to change a co-investigator listed under the permit must be submitted by the permit holder and include a description of the activity to be conducted by the proposed co-investigator, the manner in which such activity is a part of the permitted activity, and information regarding the proposed co-investigator equivalent to that required for the PI in an initial application.

2. The transfer and transport of marine mammals held for purposes of scientific research or enhancement must be authorized by NMFS.

Reporting

In addition to the reporting requirements detailed above, scientific research and enhancement permits are subject to the following reporting requirements:

1. *Annual reports.* For scientific research and enhancement permits, the annual report also shall include the following information:

a. To the extent practicable, for each marine mammal taken, imported, exported, or otherwise affected pursuant to permitted activities: The species, age, size, sex, and reproductive condition of the animal; the date, location, and manner of taking, import, or export; and for tagged animals, the dates each animal was tagged and tracked;

b. For each marine mammal part taken, imported, exported or otherwise affected pursuant to permitted activities, a description of the part and its assigned identification number;

c. The personnel and vessels involved in the conduct of the permitted research or enhancement and their respective functions;

d. For each marine mammal placed on public display: The name and location of the display facility; and the number of days the animal was displayed; and

e. A summary of all research and enhancement activities conducted during the past year.

2. *Final reports.* Scientific research and enhancement permit holders shall submit a final report to the Office Director within 180 days of the last annual report. The final report shall include:

a. A summary of all research or enhancement objectives, hypotheses, and testing (including methodology).

b. A summary of results and the manner in which such results relate to the research or enhancement objectives;

c. Where the authorized take, import, export or other activity involves a species or stock designated, or proposed to be designated, as depleted, endangered or threatened, an assessment of whether and how the scientific research or enhancement activity contributed to the achievement of any recovery objectives established for the species or stock.

d. For scientific research: An indication of where and when the research findings will be published or otherwise made available to the public or scientific community;

e. For enhancement: A description of the manner in which the enhancement program contributed significantly to maintaining or increasing distribution or abundance, enhanced the health or welfare of the species or stock, or was necessary to ensure the survival or recovery of the affected species or stock in the wild; and an assessment of the need for additional enhancement, along with specific recommendations;

f. Where marine mammals designated as depleted, endangered, or threatened are held captive under an enhancement permit, the report shall describe the manner in which the captive maintenance has contributed directly to the survival or recovery of the species or stock; and

g. A description of the disposition of any marine mammal parts, including an identification of the part as required in § 216.37(a)(4) and the manner of disposition.

3. *Special reports.* Information on marine mammals held captive must be submitted for purposes of the Marine Mammal Inventory. Such information includes animal-specific data when animals are initially obtained, and subsequent updates to be submitted for any changes in the captive holding status (i.e., animal identification, sex, estimated or actual birth date, date of acquisition or disposition by the permit holder, source of acquisition including location of the take from the wild if applicable, name of recipient if animal is transferred, notation if animal was acquired as the result of a stranding, date and cause of death, and prior notification of any sale, purchase, export, or transport). At the request of the Office Director, a necropsy report shall be submitted following report of a death.

Classification

NMFS prepared an Environmental Assessment (EA) for the 1993 proposed rule and concluded that this final rule will not significantly affect the human environment. Therefore, preparation of an Environmental Impact Statement on this action is not required by section 102(2) of NEPA or its implementing regulations. Copies of the EA remain available on request (see **ADDRESSES**). NEPA requirements as they pertain to individual permits that may be issued under these proposed regulations will be addressed on a case-by-case basis.

This final rule has been determined to be not significant for purposes of E.O. 12866 and is consistent with the President's Regulatory Reform Initiative to reduce regulatory burden on the public. This rule clarifies current permitting procedures that were found not significant during the proposed stage.

In accordance with the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), an Initial Regulatory Flexibility Analysis (IRFA) was prepared and NMFS solicited comments in the proposed rule on the economic impacts to small business entities (available upon request (see **ADDRESSES**). The IRFA determined that the projected economic impact of the proposed revisions on affected small business entities would be primarily administrative, a combination of paperwork burden costs, permit fees (some of which would be greater than the fees under current permit regulations), and the proposed requirement of a surety bond for the care, maintenance, and disposition of captive marine mammals. NMFS believed that it was unlikely that significant economic impact would result from the requirements of the proposed regulations beyond the economic impacts associated with paperwork requirements, associated permit administration, and similar requirements imposed under existing regulations. However, sufficient financial and economic data was not available for NMFS to conduct an in-depth economic analysis, particularly in regards to the permit fees and surety bond requirement. NMFS sought comments on the anticipated economic effects during the public comment period. The comments submitted in response to this request addressed public display activities exclusively, which have been eliminated from this rule.

Due to statutory changes made by Congress in the 1994 Amendments, significant portions of the proposed rule have been eliminated, including the collection of permit fees and the proposed requirement for surety bonds. In addition, activities involving the issuance of permits for purposes of public display were significantly reduced by the 1994 Amendments, further reducing any economic impact associated with paperwork costs contained in this final rule.

As a result, the impact of this final rule on small business entities is primarily in the form of paperwork burdens. Paperwork requirements include permit applications and reports, which may be annual, special, and/or final. The projected economic impact on small business entities as a result of the paperwork requirements was estimated in the IRFA as a total of $123,260 annually for a universe of 462 entities, or about $267.00 per entity, an amount not significant for purposes of the Regulatory Flexibility Act. Accordingly, the Assistant General Counsel for Legislation and Regulation of the Department of Commerce certified to the Chief Counsel for Advocacy of the Small Business Administration that this rule would not have a significant economic impact on a substantial number of small entities. As a result, a Final Regulatory Flexibility Analysis was not prepared.

This rule contains collections of information subject to the Paperwork Reduction Act. The collection of this information has been approved by the Office of Management and Budget for special exception permits, OMB Control Number 0648–0084. The public burden for collection of this information is estimated to average 29 hours per response for permit applications and major amendment requests, 3 hours for minor amendments and authorization requests, and an average of 8 hours per response for various reporting requirements that range from 12 hours for scientific research annual reports to 2 hours for necropsies.

Notwithstanding any other provision of law, no person is required to respond to nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a currently valid OMB Control Number.

NMFS has determined that these final regulations do not directly affect the coastal zone of any state with an approved coastal zone management program.

Under NOAA Administrative Order 205–11, 7.01, dated December 17, 1990, the Under Secretary for Oceans and Atmosphere has delegated to the Assistant Administrator for Fisheries, NOAA, the authority to sign material for publication in the Federal Register.

List of Subjects

15 CFR Part 902

Reporting and recordkeeping requirements.

50 CFR Part 216

Administrative practice and procedure, Exports, Imports, Indians, Marine mammals, Penalties, Reporting and recordkeeping requirements, Transportation.

50 CFR Part 222

Administrative practice and procedure, Endangered and threatened species, Exports, Imports, Reporting and recordkeeping requirements, Transportation.

Dated: May 6, 1996.

Gary Matlock,

Program Management Officer, National Marine Fisheries Service.

For reasons set out in the preamble, 15 CFR chapter IX and, under the authority of 16 U.S.C. 1361 *et seq.*, 50 CFR chapter II are amended as follows:

15 CFR CHAPTER IX

PART 902—NOAA INFORMATION COLLECTION REQUIREMENTS UNDER THE PAPERWORK REDUCTION ACT: OMB CONTROL NUMBERS

1. The authority citation for part 902 continues to read as follows:

Authority: 44 U.S.C. 3501 *et seq.*

2. In § 902.1, paragraph (b) the table is amended by removing in the left column under 50 CFR, the entries ''216.24(d)'', ''216.31'', and ''222.23'', and in the right column, in corresponding positions, the control numbers; and by adding, in numerical order, the following entries to read as follows:

§ 902.1 OMB control numbers assigned pursuant to the Paperwork Reduction Act.

* * * * *

(b) * * *

CFR part or section where the information collection requirement is located	Current OMB control number (all numbers begin with 0648–)
* * * * *	
50 CFR:	
* * * * *	
216.24(d)	–0099 and –0217
* * * * *	
216.27	–0084
216.37	–0084

CFR part or section where the information collection requirement is located	Current OMB control number (all numbers begin with 0648–)
216.38	–0084
216.39	–0084
216.41	–0084

* * * * *

50 CFR CHAPTER II

PART 216—REGULATIONS GOVERNING THE TAKING AND IMPORTING OF MARINE MAMMALS

3. The authority citation for part 216 continues to read as follows:

Authority: 16 U.S.C. 1361 *et seq.*, unless otherwise noted.

4. In § 216.3, definitions for ''Co-investigator'', ''Custody'', ''Facility'', ''Humane'', ''Intrusive research'', ''Principal investigator'', ''Public display'', and ''Rehabilitation'' are added in alphabetical order, and the definition of ''Soft part'' is revised to read as follows:

§ 216.3 Definitions.

* * * * *

Co-investigator means the on-site representative of a principal investigator.

* * * * *

Custody means holding a live marine mammal pursuant to the conditional authority granted under the MMPA, and the responsibility therein for captive maintenance of the marine mammal.

* * * * *

Facility means, in the context specific to captive marine mammals,: (1) One or more permanent primary enclosures used to hold marine mammals captive (i.e., pools, lagoons) and associated infrastructure (i.e., equipment and supplies necessary for the care and maintenance of marine mammals) where these enclosures are either located within the boundaries of a single contiguous parcel of land and water, or are grouped together within the same general area within which enclosure-to-enclosure transport is expected to be completed in less than one hour; or

(2) A traveling display/exhibit, where the enclosure(s) and associated infrastructure is transported together with the marine mammals.

* * * * *

Humane means the method of taking, import, export, or other activity which involves the least possible degree of pain and suffering practicable to the animal involved.

* * * * *

Intrusive research means a procedure conducted for bona fide scientific research involving: A break in or cutting of the skin or equivalent, insertion of an instrument or material into an orifice, introduction of a substance or object into the animal's immediate environment that is likely either to be ingested or to contact and directly affect animal tissues (i.e., chemical substances), or a stimulus directed at animals that may involve a risk to health or welfare or that may have an impact on normal function or behavior (i.e., audio broadcasts directed at animals that may affect behavior). For captive animals, this definition does not include:

(1) A procedure conducted by the professional staff of the holding facility or an attending veterinarian for purposes of animal husbandry, care, maintenance, or treatment, or a routine medical procedure that, in the reasonable judgment of the attending veterinarian, would not constitute a risk to the health or welfare of the captive animal; or

(2) A procedure involving either the introduction of a substance or object (i.e., as described in this definition) or a stimulus directed at animals that, in the reasonable judgment of the attending veterinarian, would not involve a risk to the health or welfare of the captive animal.

* * * * *

Principal investigator means the individual primarily responsible for the taking, importation, export, and any related activities conducted under a permit issued for scientific research or enhancement purposes.

Public display means an activity that provides opportunities for the public to view living marine mammals at a facility holding marine mammals captive.

* * * * *

Rehabilitation means treatment of beached and stranded marine mammals taken under section 109(h)(1) of the MMPA or imported under section 109(h)(2) of the MMPA, with the intent of restoring the marine mammal's health and, if necessary, behavioral patterns.

* * * * *

Soft part means any marine mammal part that is not a hard part. Soft parts do not include urine or fecal material.

* * * * *

5. In § 216.13, the section heading is revised and paragraph (d) is added to read as follows:

§ 216.13 Prohibited uses, possession, transportation, sales, and permits.

* * * * *

(d) Any person to violate any term, condition, or restriction of any permit issued by the Secretary.

6. In § 216.26, the section heading and paragraphs (b), (c), and (d) are revised and the introductory text to the section and paragraph (e) are added to read as follows:

§ 216.26 Collection of certain marine mammal parts without prior authorization.

Notwithstanding any other provision of this subpart:

* * * * *

(b) Notwithstanding the provisions of subpart D, soft parts that are sloughed, excreted, or discharged naturally by a living marine mammal in the wild may be collected or imported for bona fide scientific research and enhancement, provided that collection does not involve the taking of a living marine mammal in the wild.

(c) Any marine mammal part collected under paragraph (a) of this section or any marine mammal part collected and imported under paragraph (b) of this section must be registered and identified, and may be transferred or otherwise possessed, in accordance with § 216.22(c). In registering a marine mammal part collected or imported under paragraph (b) of this section, the person who collected or imported the part must also state the scientific research or enhancement purpose for which the part was collected or imported.

(d) No person may purchase, sell or trade for commercial purposes any marine mammal part collected or imported under this section.

(e) The export of parts collected without prior authorization under paragraph (b) of this section may occur if consistent with the provisions at § 216.37(d) under subpart D.

7. In subpart C, § 216.27 is added to read as follows:

§ 216.27 Release, non-releasability, and disposition under special exception permits for rehabilitated marine mammals.

(a) *Release requirements.* (1) Any marine mammal held for rehabilitation must be released within six months of capture or import unless the attending veterinarian determines that:

(i) The marine mammal might adversely affect marine mammals in the wild;

(ii) Release of the marine mammal to the wild will not likely be successful given the physical condition and behavior of the marine mammal; or

(iii) More time is needed to determine whether the release of the marine mammal to the wild will likely be successful. Releasability must be

reevaluated at intervals of no less than six months until 24 months from capture or import, at which time there will be a rebuttable presumption that release into the wild is not feasible.

(2) The custodian of the rehabilitated marine mammal shall provide written notification prior to any release into the wild.

(i) Notification shall be provided to:

(A) The NMFS Regional Director at least 15 days in advance of releasing any beached or stranded marine mammal, unless advance notice is waived in writing by the Regional Director; or

(B) The Office Director at least 30 days in advance of releasing any imported marine mammal.

(ii) Notification shall include the following:

(A) A description of the marine mammal, including its physical condition and estimated age;

(B) The date and location of release; and

(C) The method and duration of transport prior to release.

(3) The Regional Director, or the Office Director as appropriate, may:

(i) Require additional information prior to any release;

(ii) Change the date or location of release, or the method or duration of transport prior to release;

(iii) Impose additional conditions to improve the likelihood of success or to monitor the success of the release; or

(iv) Require other disposition of the marine mammal.

(4) All marine mammals must be released near wild populations of the same species, and stock if known, unless a waiver is granted by the Regional Director or the Office Director.

(5) All marine mammals released must be tagged or marked in a manner acceptable to the Regional Director or the Office Director. The tag number or description of the marking must be reported to the Regional Director or Office Director following release.

(b) *Non-releasability and postponed determinations.* (1) The attending veterinarian shall provide the Regional Director or Office Director with a written report setting forth the basis of any determination under paragraphs (a)(1)(i) through (iii) of this section.

(2) Upon receipt of a report under paragraph (b)(1) of this section, the Regional Director or Office Director, in their sole discretion, may:

(i) Order the release of the marine mammal;

(ii) Order continued rehabilitation for an additional 6 months; or

(iii) Order other disposition as authorized.

(3) No later than 30 days after a marine mammal is determined unreleasable in accordance with paragraphs (a)(1)(i) through (iii) of this section, the person with authorized custody must:

(i) Request authorization to retain or transfer custody of the marine mammal in accordance with paragraph (c) of this section, or;

(ii) Humanely euthanize the marine mammal or arrange any other disposition of the marine mammal authorized by the Regional Director or Office Director.

(4) Notwithstanding any of the provisions of this section, the Office Director may require use of a rehabilitated marine mammal for any activity authorized under subpart D in lieu of animals taken from the wild.

(5) Any rehabilitated beached or stranded marine mammal placed on public display following a non-releasability determination under paragraph (a)(1) of this section and pending disposition under paragraph (c) of this section, or any marine mammal imported for medical treatment otherwise unavailable and placed on public display pending disposition after such medical treatment is concluded, must be held in captive maintenance consistent with all requirements for public display.

(c) *Disposition for a special exception purpose.* (1) Upon receipt of an authorization request made under paragraph (b)(3)(i) of this section, or release notification under (a)(2), the Office Director may authorize the retention or transfer of custody of the marine mammal for a special exception purpose authorized under subpart D.

(2) The Office Director will first consider requests from a person authorized to hold the marine mammal for rehabilitation. The Office Director may authorize such person to retain or transfer custody of the marine mammal for scientific research, enhancement, or public display purposes.

(3) The Office Director may authorize retention or transfer of custody of the marine mammal only if:

(i) Documentation has been submitted to the Office Director that the person retaining the subject animal or the person receiving custody of the subject animal by transfer, hereinafter referred to as the recipient, complies with public display requirements of 16 U.S.C. 1374(c)(2)(A) or, for purposes of scientific research and enhancement, holds an applicable permit, or an application for such a special exception permit under § 216.33 or a request for a major amendment under § 216.39 has been submitted to the Office Director and has been found complete;

(ii) The recipient agrees to hold the marine mammal in conformance with all applicable requirements and standards; and

(iii) The recipient acknowledges that the marine mammal is subject to seizure by the Office Director:

(A) If, at any time pending issuance of the major amendment or permit, the Office Director determines that seizure is necessary in the interest of the health or welfare of the marine mammal;

(B) If the major amendment or permit is denied; or

(C) If the recipient is issued a notice of violation and assessment, or is subject to permit sanctions, in accordance with 15 CFR part 904.

(4) There shall be no remuneration associated with any transfer, provided that, the transferee may reimburse the transferor for any and all costs associated with the rehabilitation and transport of the marine mammal.

(5) Marine mammals undergoing rehabilitation or pending disposition under this section shall not be subject to public display, unless such activities are specifically authorized by the Regional Director or the Office Director, and conducted consistent with the requirements applicable to public display. Such marine mammals shall not be trained for performance or be included in any aspect of a program involving interaction with the public; and

(6) Marine mammals undergoing rehabilitation shall not be subject to intrusive research, unless such activities are specifically authorized by the Office Director in consultation with the Marine Mammal Commission and its Committee of Scientific Advisors on Marine Mammals, and are conducted pursuant to a scientific research permit.

(d) Reporting. In addition to the report required under § 216.22(b), the person authorized to hold marine mammals for rehabilitation must submit reports to the Regional Director or Office Director regarding release or other disposition. These reports must be provided in the form and frequency specified by the Regional Director or Office Director.

8. In subpart D, §§ 216.31 through 216.34 are revised; §§ 216.35 through 216.44 are added; and § 216.30 and §§ 216.46 through 216.49 are added and reserved to read as follows:

Subpart D—Special Exception Permits

216.30 [Reserved]
216.31 Definitions.
216.32 Scope.
216.33 Permit application submission, review, and decision procedures.
216.34 Issuance criteria.
216.35 Permit restrictions.
216.36 Permit conditions.

216.37 Marine mammal parts.
216.38 Reporting.
216.39 Permit amendments.
216.40 Penalties and permit sanctions.
216.41 Permits for scientific research and enhancement.
216.42 Photography. [Reserved]
216.43 Public display. [Reserved]
216.44 Applicability/transition.
216.45 General authorization.
216.46–216.49 [Reserved]

§ 216.30 [Reserved]

§ 216.31 Definitions.

For the purpose of this subpart, the definitions set forth in 50 CFR part 217 shall apply to all threatened and endangered marine mammals, unless a more restrictive definition exists under the MMPA or part 216.

§ 216.32 Scope.

The regulations of this subpart apply to:

(a) All marine mammals and marine mammal parts taken or born in captivity after December 20, 1972; and

(b) All marine mammals and marine mammal parts that are listed as threatened or endangered under the ESA.

§ 216.33 Permit application submission, review, and decision procedures.

(a) *Application submission.* Persons seeking a special exemption permit under this subpart must submit an application to the Office Director. The application must be signed by the applicant, and provide in a properly formatted manner all information necessary to process the application. Written instructions addressing information requirements and formatting may be obtained from the Office Director upon request.

(b) *Applications to export living marine mammals.* For applicants seeking a special exception permit to export living marine mammals, the application must:

(1) Be submitted through the Convention on International Trade in Endangered Fauna and Flora management authority of the foreign government or, if different, the appropriate agency or agencies of the foreign government that exercises oversight over marine mammals.

(2) Include a certification from the foreign government that:

(i) The information set forth in the application is accurate;

(ii) The laws and regulations of the foreign governmentinvolved allow enforcement of the terms and conditions of the permit, and that the foreign government will enforce all terms and conditions; and

(iii) The foreign government involved will afford comity to any permit amendment, modification, suspension or revocation decision.

(c) *Initial review.* (1) NMFS will notify the applicant of receipt of the application.

(2) During the initial review, the Office Director will determine:

(i) Whether the application is complete.

(ii) Whether the proposed activity is for purposes authorized under this subpart.

(iii) If the proposed activity is for enhancement purposes, whether the species or stock identified in the application is in need of enhancement for its survival or recovery and whether the proposed activity will likely succeed in its objectives.

(iv) Whether the activities proposed are to be conducted consistent with the permit restrictions and permit specific conditions as described in § 216.35 and § 216.36(a).

(v) Whether sufficient information is included regarding the environmental impact of the proposed activity to enable the Office Director:

(A) To make an initial determination under the National Environmental Policy Act (NEPA) as to whether the proposed activity is categorically excluded from preparation of further environmental documentation, or whether the preparation of an environmental assessment (EA) or environmental impact statement (EIS) is appropriate or necessary; and

(B) To prepare an EA or EIS if an initial determination is made by the Office Director that the activity proposed is not categorically excluded from such requirements.

(3) The Office Director may consult with the Marine Mammal Commission (Commission) and its Committee of Scientific Advisors on Marine Mammals (Committee) in making these initial, and any subsequent, determinations.

(4) Incomplete applications will be returned with explanation. If the applicant fails to resubmit a complete application or correct the identified deficiencies within 60 days, the application will be deemed withdrawn. Applications that propose activities inconsistent with this subpart will be returned with explanation, and will not be considered further.

(d) *Notice of receipt and application review.* (1) Upon receipt of a valid, complete application, and the preparation of any NEPA documentation that has been determined initially to be required, the Office Director will publish a notice of receipt in the Federal Register. The notice will:

(i) Summarize the application, including:

(A) The purpose of the request;

(B) The species and number of marine mammals;

(C) The type and manner of special exception activity proposed;

(D) The location(s) in which the marine mammals will be taken, from which they will be imported, or to which they will be exported; and

(E) The requested period of the permit.

(ii) List where the application is available for review.

(iii) Invite interested parties to submit written comments concerning the application within 30 days of the date of the notice.

(iv) Include a NEPA statement that an initial determination has been made that the activity proposed is categorically excluded from the requirement to prepare an EA or EIS, that an EA was prepared resulting in a finding of no significant impact, or that a final EIS has been prepared and is available for review.

(2) The Office Director will forward a copy of the complete application to the Commission for comment. If no comments are received within 45 days (or such longer time as the Office Director may establish) the Office Director will consider the Commission to have no objection to issuing a permit.

(3) The Office Director may consult with any other person, institution, or agency concerning the application.

(4) Within 30 days of publication of the notice of receipt in the Federal Register, any interested party may submit written comments or may request a public hearing on the application.

(5) If the Office Director deems it advisable, the Office Director may hold a public hearing within 60 days of publication of the notice of receipt in the Federal Register. Notice of the date, time, and place of the public hearing will be published in the Federal Register not less than 15 days in advance of the public hearing. Any interested person may appear in person or through representatives and may submit any relevant material, data, views, or comments. A summary record of the hearing will be kept.

(6) The Office Director may extend the period during which any interested party may submit written comments. Notice of the extension must be published in the Federal Register within 60 days of publication of the notice of receipt in the Federal Register.

(7) If, after publishing a notice of receipt, the Office Director determines on the basis of new information that an EA or EIS must be prepared, the Office Director must deny the permit unless an EA is prepared with a finding of no significant impact. If a permit is denied under these circumstances the application may be resubmitted with information sufficient to prepare an EA or EIS, and will be processed as a new application.

(e) *Issuance or denial procedures.* (1) Within 30 days of the close of the public hearing or, if no public hearing is held, within 30 days of the close of the public comment period, the Office Director will issue or deny a special exception permit.

(2) The decision to issue or deny a permit will be based upon:

(i) All relevant issuance criteria set forth at § 216.34;

(ii) All purpose-specific issuance criteria as appropriate set forth at § 216.41, § 216.42, and § 216.43;

(iii) All comments received or views solicited on the permit application; and

(iv) Any other information or data that the Office Director deems relevant.

(3) If the permit is issued, upon receipt, the holder must date and sign the permit, and return a copy of the original to the Office Director. The permit shall be effective upon the permit holder's signing of the permit. In signing the permit, the holder:

(i) Agrees to abide by all terms and conditions set forth in the permit, and all restrictions and relevant regulations under this subpart; and

(ii) Acknowledges that the authority to conduct certain activities specified in the permit is conditional and subject to authorization by the Office Director.

(4) Notice of the decision of the Office Director shall be published in the Federal Register within 10 days after the date of permit issuance or denial and shall indicate where copies of the permit, if issued, may be reviewed or obtained. If the permit issued involves marine mammals listed as endangered or threatened under the ESA, the notice shall include a finding by the Office Director that the permit:

(i) Was applied for in good faith;

(ii) If exercised, will not operate to the disadvantage of such endangered or threatened species; and

(iii) Is consistent with the purposes and policy set forth in section 2 of the ESA.

(5) If the permit is denied, the Office Director shall provide the applicant with an explanation for the denial.

(6) Under the MMPA, the Office Director may issue a permit for scientific research before the end of the public comment period if delaying issuance could result in injury to a species, stock, or individual, or in loss of unique research opportunities. The Office Director also may waive the 30-day comment period required under the ESA in an emergency situation where the health or life of an endangered or threatened marine mammal is threatened and no reasonable alternative is available. If a permit is issued under these circumstances, notice of such issuance before the end of the comment period shall be published in the Federal Register within 10 days of issuance.

(7) The applicant or any party opposed to a permit may seek judicial review of the terms and conditions of such permit or of a decision to deny such permit. Review may be obtained by filing a petition for review with the appropriate U.S. District Court as provided for by law.

§ 216.34 Issuance criteria.

(a) For the Office Director to issue any permit under this subpart, the applicant must demonstrate that:

(1) The proposed activity is humane and does not present any unnecessary risks to the health and welfare of marine mammals;

(2) The proposed activity is consistent with all restrictions set forth at § 216.35 and any purpose-specific restrictions as appropriate set forth at § 216.41, § 216.42, and § 216.43;

(3) The proposed activity, if it involves endangered or threatened marine mammals, will be conducted consistent with the purposes and policies set forth in section 2 of the ESA;

(4) The proposed activity by itself or in combination with other activities, will not likely have a significant adverse impact on the species or stock;

(5) Whether the applicant's expertise, facilities, and resources are adequate to accomplish successfully the objectives and activities stated in the application;

(6) If a live animal will be held captive or transported, the applicant's qualifications, facilities, and resources are adequate for the proper care and maintenance of the marine mammal; and

(7) Any requested import or export will not likely result in the taking of marine mammals or marine mammal parts beyond those authorized by the permit.

(b) The opinions or views of scientists or other persons or organizations knowledgeable of the marine mammals that are the subject of the application or of other matters germane to the application will be considered.

§ 216.35 Permit restrictions.

The following restrictions shall apply to all permits issued under this subpart:

(a) The taking, importation, export, or other permitted activity involving marine mammals and marine mammal parts shall comply with the regulations of this subpart.

(b) The maximum period of any special exception permit issued, or any major amendment granted, is five years from the effective date of the permit or major amendment. In accordance with the provisions of § 216.39, the period of a permit may be extended by a minor amendment up to 12 months beyond that established in the original permit.

(c) Except as provided for in § 216.41(c)(1)(v), marine mammals or marine mammal parts imported under the authority of a permit must be taken or imported in a humane manner, and in compliance with the Acts and any applicable foreign law. Importation of marine mammals and marine mammal parts is subject to the provisions of 50 CFR part 14.

(d) The permit holder shall not take from the wild any marine mammal which at the time of taking is either unweaned or less than eight months old, or is a part of a mother-calf/pup pair, unless such take is specifically authorized in the conditions of the special exception permit. Additionally, the permit holder shall not import any marine mammal that is pregnant or lactating at the time of taking or import, or is unweaned or less than eight months old unless such import is specifically authorized in the conditions of the special exception permit.

(e) Captive marine mammals shall not be released into the wild unless specifically authorized by the Office Director under a scientific research or enhancement permit.

(f) The permit holder is responsible for all activities of any individual who is operating under the authority of the permit;

(g) Individuals conducting activities authorized under the permit must possess qualifications commensurate with their duties and responsibilities, or must be under the direct supervision of a person with such qualifications;

(h) Persons who require state or Federal licenses to conduct activities authorized under the permit must be duly licensed when undertaking such activities;

(i) Special exception permits are not transferable or assignable to any other person, and a permit holder may not require any direct or indirect compensation from another person in return for requesting authorization for such person to conduct the taking,

import, or export activities authorized under the subject permit;

(j) The permit holder or designated agent shall possess a copy of the permit when engaged in a permitted activity, when the marine mammal is in transit incidental to such activity, and whenever marine mammals or marine mammal parts are in the possession of the permit holder or agent. A copy of the permit shall be affixed to any container, package, enclosure, or other means of containment, in which the marine mammals or marine mammal parts are placed for purposes of transit, supervision, or care. For marine mammals held captive and marine mammal parts in storage, a copy of the permit shall be kept on file in the holding or storage facility.

§ 216.36 Permit conditions.

(a) *Specific conditions.* (1) Permits issued under this subpart shall contain specific terms and conditions deemed appropriate by the Office Director, including, but not limited to:

(i) The number and species of marine mammals that are authorized to be taken, imported, exported, or otherwise affected;

(ii) The manner in which marine mammals may be taken according to type of take;

(iii) The location(s) in which the marine mammals may be taken, from which they may be imported, or to which they may be exported, as applicable, and, for endangered or threatened marine mammal species to be imported or exported, the port of entry or export;

(iv) The period during which the permit is valid.

(2) [Reserved]

(b) *Other conditions.* In addition to the specific conditions imposed pursuant to paragraph (a) of this section, the Office Director shall specify any other permit conditions deemed appropriate.

§ 216.37 Marine mammal parts.

With respect to marine mammal parts acquired by take or import authorized under a permit issued under this subpart:

(a) Marine mammal parts are transferrable if:

(1) The person transferring the part receives no remuneration of any kind for the marine mammal part;

(2) The person receiving the marine mammal part is:

(i) An employee of NMFS, the U.S. Fish and Wildlife Service, or any other governmental agency with conservation and management responsibilities, who receives the part in the course of their official duties;

(ii) A holder of a special exception permit which authorizes the take, import, or other activity involving the possession of a marine mammal part of the same species as the subject part; or

(iii) In the case of marine mammal parts from a species that is not depleted, endangered or threatened, a person who is authorized under section 112(c) of the MMPA and subpart C of this part to take or import marine mammals or marine mammal parts;

(iv) Any other person specifically authorized by the Regional Director, consistent with the requirements of paragraphs (a)(1) and (a)(3) through (6) of this section.

(3) The marine mammal part is transferred for the purpose of scientific research, maintenance in a properly curated, professionally accredited scientific collection, or education, provided that, for transfers for educational purposes, the recipient is a museum, educational institution or equivalent that will ensure that the part is available to the public as part of an educational program;

(4) A unique number assigned by the permit holder is marked on or affixed to the marine mammal part or container;

(5) The person receiving the marine mammal part agrees that, as a condition of receipt, subsequent transfers may only occur subject to the provisions of paragraph (a) of this section; and

(6) Within 30 days after the transfer, the person transferring the marine mammal part notifies the Regional Director of the transfer, including a description of the part, the person to whom the part was transferred, the purpose of the transfer, certification that the recipient has agreed to comply with the requirements of paragraph (a) of this section for subsequent transfers, and, if applicable, the recipient's permit number.

(b) Marine mammal parts may be loaned to another person for a purpose described in paragraph (a)(3) of this section and without the agreement and notification required under paragraphs (a)(5) and (6) of this section, if:

(1) A record of the loan is maintained; and

(2) The loan is for not more than one year. Loans for a period greater than 12 months, including loan extensions or renewals, require notification of the Regional Director under paragraph (a)(6).

(c) Unless other disposition is specified in the permit, a holder of a special exception permit may retain marine mammal parts not destroyed or otherwise disposed of during or after a scientific research or enhancement activity, if such marine mammal parts are:

(1) Maintained as part of a properly curated, professionally accredited collection; or

(2) Made available for purposes of scientific research or enhancement at the request of the Office Director.

(d) Marine mammal parts may be exported and subsequently reimported by a permit holder or subsequent authorized recipient, for the purpose of scientific research, maintenance in a properly curated, professionally accredited scientific collection, or education, provided that:

(1) The permit holder or other person receives no remuneration for the marine mammal part;

(2) A unique number assigned by the permit holder is marked on or affixed to the marine mammal specimen or container;

(3) The marine mammal part is exported or reimported in compliance with all applicable domestic and foreign laws;

(4) If exported or reimported for educational purposes, the recipient is a museum, educational institution, or equivalent that will ensure that the part is available to the public as part of an educational program; and

(5) Special reports are submitted within 30 days after both export and reimport as required by the Office Director under § 216.38.

§ 216.38 Reporting.

All permit holders must submit annual, final, and special reports in accordance with the requirements established in the permit, and any reporting format established by the Office Director.

§ 216.39 Permit amendments.

(a) *General.* Special exception permits may be amended by the Office Director. Major and minor amendments may be made to permits in response to, or independent of, a request from the permit holder. Amendments must be consistent with the Acts and comply with the applicable provisions of this subpart.

(1) A ''major amendment'' means any change to the permit specific conditions under § 216.36(a) regarding:

(i) The number and species of marine mammals that are authorized to be taken, imported, exported, or otherwise affected;

(ii) The manner in which these marine mammals may be taken, imported, exported, or otherwise affected, if the proposed change may result in an increased level of take or risk of adverse impact;

(iii) The location(s) in which the marine mammals may be taken, from which they may be imported, and to which they may be exported, as applicable; and

(iv) The duration of the permit, if the proposed extension would extend the duration of the permit more than 12 months beyond that established in the original permit.

(2) A ''minor amendment'' means any amendment that does not constitute a major amendment.

(b) *Amendment requests and proposals.* (1) Requests by a permit holder for an amendment must be submitted in writing and include the following:

(i) The purpose and nature of the amendment;

(ii) Information, not previously submitted as part of the permit application or subsequent reports, necessary to determine whether the amendment satisfies all issuance criteria set forth at § 216.34, and, as appropriate, § 216.41, § 216.42, and § 216.43.

(iii) Any additional information required by the Office Director for purposes of reviewing the proposed amendment.

(2) If an amendment is proposed by the Office Director, the permit holder will be notified of the proposed amendment, together with an explanation.

(c) *Review of proposed amendments.* (1) *Major amendments.* The provisions of § 216.33(d) and (e) governing notice of receipt, review and decision shall apply to all proposed major amendments.

(2) *Minor amendments.* (i) After reviewing all appropriate information, the Office Director will provide the permit holder with written notice of the decision on a proposed or requested amendment, together with an explanation for the decision.

(ii) If the minor amendment extends the duration of the permit 12 months or less from that established in the original permit, notice of the minor amendment will be published in the Federal Register within 10 days from the date of the Office Director's decision.

(iii) A minor amendment will be effective upon a final decision by the Office Director.

§ 216.40 Penalties and permit sanctions.

(a) Any person who violates any provision of this subpart or permit issued thereunder is subject to civil and criminal penalties, permit sanctions and forfeiture as authorized under the Acts, and 15 CFR part 904.

(b) All special exception permits are subject to suspension, revocation, modification and denial in accordance with the provisions of subpart D of 15 CFR part 904.

§ 216.41 Permits for scientific research and enhancement.

In addition to the requirements under § 216.33 through § 216.38, permits for scientific research and enhancement are governed by the following requirements:

(a) *Applicant.* (1) For each application submitted under this section, the applicant shall be the principal investigator responsible for the overall research or enhancement activity. If the research or enhancement activity will involve a periodic change in the principal investigator or is otherwise controlled by and dependent upon another entity, the applicant may be the institution, governmental entity, or corporation responsible for supervision of the principal investigator.

(2) For any scientific research involving captive maintenance, the application must include supporting documentation from the person responsible for the facility or other temporary enclosure.

(b) *Issuance Criteria.* For the Office Director to issue any scientific research or enhancement permit, the applicant must demonstrate that:

(1) The proposed activity furthers a bona fide scientific or enhancement purpose;

(2) If the lethal taking of marine mammals is proposed:

(i) Non-lethal methods for conducting the research are not feasible; and

(ii) For depleted, endangered, or threatened species, the results will directly benefit that species or stock, or will fulfill a critically important research need.

(3) Any permanent removal of a marine mammal from the wild is consistent with any applicable quota established by the Office Director.

(4) The proposed research will not likely have significant adverse effects on any other component of the marine ecosystem of which the affected species or stock is a part.

(5) For species or stocks designated or proposed to be designated as depleted, or listed or proposed to be listed as endangered or threatened:

(i) The proposed research cannot be accomplished using a species or stock that is not designated or proposed to be designated as depleted, or listed or proposed to be listed as threatened or endangered;

(ii) The proposed research, by itself or in combination with other activities will not likely have a long-term direct or indirect adverse impact on the species or stock;

(iii) The proposed research will either:

(A) Contribute to fulfilling a research need or objective identified in a species recovery or conservation plan, or if there is no conservation or recovery plan in place, a research need or objective identified by the Office Director in stock assessments established under section 117 of the MMPA;

(B) Contribute significantly to understanding the basic biology or ecology of the species or stock, or to identifying, evaluating, or resolving conservation problems for the species or stock; or

(C) Contribute significantly to fulfilling a critically important research need.

(6) For proposed enhancement activities:

(i) Only living marine mammals and marine mammal parts necessary for enhancement of the survival, recovery, or propagation of the affected species or stock may be taken, imported, exported, or otherwise affected under the authority of an enhancement permit. Marine mammal parts would include in this regard clinical specimens or other biological samples required for the conduct of breeding programs or the diagnosis or treatment of disease.

(ii) The activity will likely contribute significantly to maintaining or increasing distribution or abundance, enhancing the health or welfare of the species or stock, or ensuring the survival or recovery of the affected species or stock in the wild.

(iii) The activity is consistent with:

(A) An approved conservation plan developed under section 115(b) of the MMPA or recovery plan developed under section 4(f) of the ESA for the species or stock; or

(B) If there is no conservation or recovery plan, with the Office Director's evaluation of the actions required to enhance the survival or recovery of the species or stock in light of the factors that would be addressed in a conservation or recovery plan.

(iv) An enhancement permit may authorize the captive maintenance of a marine mammal from a threatened, endangered, or depleted species or stock only if the Office Director determines that:

(A) The proposed captive maintenance will likely contribute directly to the survival or recovery of the species or stock by maintaining a viable gene pool, increasing productivity, providing necessary biological information, or establishing animal reserves required to support directly these objectives; and

(B) The expected benefit to the species or stock outweighs the expected benefits of alternatives that do not require removal of marine mammals from the wild.

(v) The Office Director may authorize the public display of marine mammals held under the authority of an enhancement permit only if:

(A) The public display is incidental to the authorized captive maintenance;

(B) The public display will not interfere with the attainment of the survival or recovery objectives;

(C) The marine mammals will be held consistent with all requirements and standards that are applicable to marine mammals held under the authority of the Acts and the Animal Welfare Act, unless the Office Director determines that an exception is necessary to implement an essential enhancement activity; and

(D) The marine mammals will be excluded from any interactive program and will not be trained for performance.

(vi) The Office Director may authorize non-intrusive scientific research to be conducted while a marine mammal is held under the authority of an enhancement permit, only if such scientific research:

(A) Is incidental to the permitted enhancement activities; and

(B) Will not interfere with the attainment of the survival or recovery objectives.

(c) *Restrictions*. (1) The following restrictions apply to all scientific research permits issued under this subpart:

(i) Research activities must be conducted in the manner authorized in the permit.

(ii) Research results shall be published or otherwise made available to the scientific community in a reasonable period of time.

(iii) Research activities must be conducted under the direct supervision of the principal investigator or a co-investigator identified in the permit.

(iv) Personnel involved in research activities shall be reasonable in number and limited to:

(A) Individuals who perform a function directly supportive of and necessary to the permitted research activity; and

(B) Support personnel included for the purpose of training or as backup personnel for persons described in paragraph (c)(1)(iv)(A).

(v) Any marine mammal part imported under the authority of a scientific research permit must not have been obtained as the result of a lethal taking that would be inconsistent with the Acts, unless authorized by the Office Director.

(vi) Marine mammals held under a permit for scientific research shall not be placed on public display, included in an interactive program or activity, or trained for performance unless such activities:

(A) Are necessary to address scientific research objectives and have been specifically authorized by the Office Director under the scientific research permit; and

(B) Are conducted incidental to and do not in any way interfere with the permitted scientific research; and

(C) Are conducted in a manner consistent with provisions applicable to public display, unless exceptions are specifically authorized by the Office Director.

(vii) Any activity conducted incidental to the authorized scientific research activity must not involve any taking of marine mammals beyond what is necessary to conduct the research (i.e., educational and commercial photography).

(2) Any marine mammal or progeny held in captive maintenance under an enhancement permit shall be returned to its natural habitat as soon as feasible, consistent with the terms of the enhancement permit and the objectives of an approved conservation or recovery plan. In accordance with section 10(j) of the ESA, the Office Director may authorize the release of any population of an endangered or threatened species outside the current range of such species if the Office Director determines that such release will further the conservation of such species.

§ 216.42 Photography. [Reserved]

§ 216.43 Public display. [Reserved]

§ 216.44 Applicability/transition.

(a) *General*. The regulations of this subpart are applicable to all persons, including persons holding permits or other authorizing documents issued before June 10, 1996, by NMFS for the take, import, export, or conduct of any otherwise prohibited activity involving a marine mammal or marine mammal part for special exception purposes.

(b) *Scientific research*. Any intrusive research as defined in § 216.3, initiated after June 10, 1996, must be authorized under a scientific research permit. Intrusive research authorized by the Office Director to be conducted on captive marine mammals held for public display purposes prior to June 10, 1996, must be authorized under a scientific research permit one year after June 10, 1996.

* * * * *

§§ 216.46–216.49 [Reserved]

PART 222—ENDANGERED FISH OR WILDLIFE

9. The authority citation for part 222 is revised to read as follows:

Authority: 16 U.S.C. 1531 *et seq*.

10. In § 222.23, the first sentence in paragraph (b) is revised to read as follows:

§ 222.23 Permits for scientific purposes or to enhance the propagation or survival of the affected endangered species.

* * * * *

(b) *Application procedures*. To obtain such a permit, an application must be made to the Director in accordance with this subpart, except for marine mammal permits which shall be issued in accordance with the provisions of part 216, subpart D of this chapter, and sea turtle permits which shall be issued in accordance with part 220, subpart E of this chapter.

* * * * *

[FR Doc. 96–11776 Filed 5–9–96; 8:45 am]

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federal register

Friday
May 10, 1996

Part X

The President

Executive Order 13001—Establishing an Emergency Board To Investigate a Dispute Between Certain Railroads Represented by the National Railway Labor Conference and Their Employees Represented by the Transportation Communications International Union

Federal Register
Vol. 61, No. 92
Friday, May 10, 1996

Presidential Documents

Title 3—

The President

Executive Order 13001 of May 8, 1996

Establishing an Emergency Board To Investigate a Dispute Between Certain Railroads Represented by the National Railway Labor Conference and Their Employees Represented by the Transportation Communications International Union

A dispute exists between certain railroads represented by the National Railway Labor Conference and their employees represented by the Transportation Communications International Union. The railroads involved in this dispute are designated on the attached list, which is made a part of this order.

This dispute has not heretofore been adjusted under the provisions of the Railway Labor Act, as amended (45 U.S.C. 151 *et seq.*) (the ''Act'').

In the judgment of the National Mediation Board, this dispute threatens substantially to interrupt interstate commerce to a degree that would deprive a section of the country of essential transportation service.

NOW, THEREFORE, by the authority vested in me as President by the Constitution and the laws of the United States, including section 10 of the Act (45 U.S.C. 160), it is hereby ordered as follows:

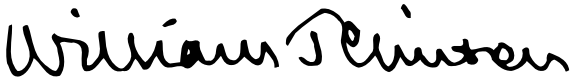
Section 1. *Establishment of Emergency Board (''Board'').* There is established effective May 8, 1996, a Board of three members to be appointed by the President to investigate the dispute. No member shall be pecuniarily or otherwise interested in any organization of railroad employees or any railroad carrier. The Board shall perform its functions subject to the availability of funds.

Sec. 2. *Report.* The Board shall report to the President with respect to the dispute within 30 days of its creation.

Sec. 3. *Maintaining Conditions.* As provided by section 10 of the Act, from the date of the creation of the Board and for 30 days after the Board has made its report to the President, no change, except by agreement of the parties shall be made by the railroads or the employees in the conditions out of which the dispute arose.

Sec. 4. *Records Maintenance.* The records and files of the Board are records of the Office of the President and upon the Board's termination shall be maintained in the physical custody of the National Mediation Board.

Sec. 5. *Expiration.* The Board shall terminate upon the submission of the report provided for in sections 2 and 3 of this order.



THE WHITE HOUSE,
May 8, 1996.

RAILROADS

Alameda Belt Line Railway

Alton & Southern Railroad

American Refrigerator Transit Company

Arkansas Memphis Bridge Company

Atchison, Topeka and Santa Fe Railway Company

Bangor and Aroostook Railroad Company

Belt Railway Company of Chicago

Brownsville & Matamoros Bridge Company

Burlington Northern Railroad Company
- Allouez Taconite Facility
- Brainerd Timber Treating Plant
- Western Fruit Express Company

Camas Prairie Railroad Company

Canadian National North America

Central California Traction Company

Chicago Heights Terminal Railroad

Chicago Heights Terminal Transfer Railroad

Chicago and North Western Railway Company

Chicago South Shore and South Bend Railroad

Consolidated Rail Corporation

CSX Transportation, Inc.
- The Baltimore and Ohio Railroad Company (former)
- The Chesapeake and Ohio Railway Company (former)
- Louisville and Nashville Railroad Company (former)
- Seaboard Coast Line Railroad Company (former)

Houston Belt and Terminal Railway

Joint Railroad Agency - National Stock Yards

The Kansas City Southern Railway Company
- CP-Kansas City Southern Joint Agency

Kansas City Terminal Railway Company

Lake Superior & Ishpeming Railroad Company

Los Angeles Junction Railroad Company

Missouri Pacific Railroad

New Orleans Public Belt Railroad

Norfolk and Portsmouth Belt Line Railroad Company

Norfolk Southern Corporation

Norfolk Southern Railway Company
- The Alabama Great Southern Railroad Company
- Atlantic & East Carolina Railway Company
- Central of Georgia Railroad Company
- The Cincinnati, New Orleans and Texas Pacific Railway Company
- Georgia Southern and Florida Railway Company
- Norfolk & Western Railway Company
- Tennessee, Alabama and Georgia Railway Company

Northern Indiana Commuter Transportation District

Peoria and Pekin Union Railway Company

The Pittsburgh, Chartiers & Youghiogheny Railway Company

Port Terminal Railroad Association

Portland Terminal Railroad Company

Spokane International Railroad

Terminal Railroad Association of St. Louis

Texarkana Union Station Trust Company

Union Pacific Fruit Express

Union Pacific Railroad

Galveston, Houston and Henderson Railroad

Missouri-Kansas-Texas Railroad

Oklahoma, Kansas & Texas Railroad

Western Pacific Railroad

Wichita Terminal Association

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The rules and proposed rules in this list were editorially compiled as an aid to Federal Register users. Inclusion or exclusion from this list has no legal significance.

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Dairy products; grading, inspection, and standards:

Monterey (monterey jack) cheese; published 4-10-96

Sheep promotion, research, and consumer information; published 5-9-96

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Marine mammals:

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Small takes by harassment in Arctic waters; published 4-10-96

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Loan underwriting; Federal regulatory review; comments due by 5-15-96; published 4-15-96

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Phenylpropanolamine preparation drug products; warning label; comments due by 5-14-96; published 2-14-96

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OTC first aid antibiotic drug products; final monograph; comments due by 5-14-96; published 2-14-96

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Detectable warnings at curb ramps, hazardous vehicular areas, and reflecting pools; comments due by 5-13-96; published 4-12-96

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LIST OF PUBLIC LAWS

Note: No public bills which have become law were received by the Office of the Federal Register for inclusion in today's **List of Public Laws**.

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