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Presidential Documents

Title 3—

The President

Executive Order 13284 of January 23, 2003

Amendment of Executive Orders, and Other Actions, in Connection With the Establishment of the Department of Homeland Security

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the Homeland Security Act of 2002 (Public Law 107–296), and the National Security Act of 1947, as amended (50 U.S.C. 401 *et seq.*), and in order to reflect responsibilities vested in the Secretary of Homeland Security and take other actions in connection with the establishment of the Department of Homeland Security, it is hereby ordered as follows:

Section 1. Executive Order 13234 of November 9, 2001 (''Presidential Task Force on Citizen Preparedness in the War on Terrorism''), is amended by inserting ''the Department of Homeland Security,'' after ''the Office of Management and Budget,'' in section 2(a).

Sec. 2. Executive Order 13231 of October 16, 2001 (''Critical Infrastructure Protection in the Information Age''), is amended by:

(a) inserting ''(i) Secretary of Homeland Security;'' after ''or their designees:'' in section 6(a); and

(b) renumbering the subsequent subsections in section 6(a) appropriately.

Sec. 3. Executive Order 13228 of October 8, 2001 (''Establishing the Office of Homeland Security and the Homeland Security Council''), is amended by inserting ''the Secretary of Homeland Security,'' after ''the Secretary of Transportation,'' in section 5(b). Further, during the period from January 24, 2003, until March 1, 2003, the Secretary of Homeland Security shall have the responsibility for coordinating the domestic response efforts otherwise assigned to the Assistant to the President for Homeland Security pursuant to section 3(g) of Executive Order 13228.

Sec. 4. Executive Order 13224 of September 23, 2001 (''Blocking Property and Prohibiting Transactions with Persons Who Commit, Threaten to Commit, or Support Terrorism''), as amended, is further amended by:

(a) inserting '', the Secretary of Homeland Security,'' after ''the Secretary of the Treasury'' in sections 1(b) and 1(d) (the first time it appears); and

(b) inserting '', the Secretary of Homeland Security,'' after ''the Secretary of State'' in sections 1(c) and 1(d) (the second time it appears), 5 (wherever it appears), and 7.

Sec. 5. Executive Order 13151 of April 27, 2000 (''Global Disaster Information Network''), is amended by:

(a) inserting ''(8) Department of Homeland Security;'' after ''(7) Department of Energy;'' in section 2(a); and

(b) renumbering the subsequent subsections in section 2(a) appropriately.

Sec. 6. Executive Order 13122 of May 25, 1999 (''Interagency Task Force on the Economic Development of the Southwest Border''), is amended by inserting ''Secretary of Homeland Security,'' after ''Secretary of the Treasury,'' in section 1(b).

Sec. 7. Executive Order 13048 of June 10, 1997 (''Improving Administrative Management in the Executive Branch''), is amended by:

(a) inserting ''15. Department of Homeland Security;'' after ''14. Department of Veterans Affairs;'' in section 1(a); and

(b) renumbering all subsequent subsections in section 1(a) appropriately.

Sec. 8. Executive Order 12992 of March 15, 1996 (''President's Council on Counter-Narcotics''), as amended, is further amended by:

(a) inserting ''(n) Secretary of Homeland Security;'' after ''(m) Secretary of Veterans Affairs;'' in section 2; and

(b) relettering all subsequent subsections in section 2 appropriately.

Sec. 9. Executive Order 12881 of November 23, 1993 (''Establishment of the National Science and Technology Council''), is amended by:

(a) inserting ''(i) Secretary of Homeland Security;'' after ''(h) Secretary of the Interior;'' in section 2; and

(b) relettering all subsequent subsections in section 2 appropriately.

Sec. 10. Executive Order 12859 of August 16, 1993 (''Establishment of the Domestic Policy Council''), is amended by:

(a) inserting ''(o) Secretary of Homeland Security;'' after ''(n) Secretary of the Treasury;'' in section 2; and

(b) relettering all subsequent subsections in section 2 appropriately.

Sec. 11. Executive Order 12590 of March 26, 1987 (''National Drug Policy Board''), is amended by:

(a) inserting ''(13) the Secretary of Homeland Security;'' after ''(12) the Secretary of Education;'' in section 1(b); and

(b) renumbering all subsequent subsections in section 1(b) appropriately.

Sec. 12. Executive Order 12260 of December 31, 1980 (''Agreement on Government Procurement''), as amended, is further amended by:

(a) inserting ''14. Department of Homeland Security'' after ''13. Department of Health and Human Services'' in the Annex; and

(b) renumbering all subsequent subsections in the Annex appropriately.

Sec. 13. Executive Order 11958 of January 18, 1977 (''Administration of Arms Export Controls''), as amended, is further amended by:

(a) striking ''Secretary of the Treasury'' wherever it appears in section 1(l)(2) and inserting ''Attorney General'' in lieu thereof; and

(b) inserting ''the Attorney General,'' after ''the Secretary of the Treasury,'' in section 2(a).

Sec. 14. Executive Order 11423 of August 16, 1968 (''Providing for the Performance of Certain Functions Heretofore Performed by the President with Respect to Certain Facilities Constructed and Maintained on the Borders of the United States''), as amended, is further amended by inserting ''the Secretary of Homeland Security,'' after ''the Secretary of Transportation,'' in section 1(b).

Sec. 15. Executive Order 10865 of February 20, 1960 (''Safeguarding Classified Information Within Industry''), as amended, is further amended by inserting ''the Secretary of Homeland Security,'' after ''the Secretary of Energy,'' in section 1.

Sec. 16. Executive Order 13011 of July 16, 1996 (''Federal Information Technology''), is amended by:

(a) inserting ''15. Department of Homeland Security;'' after ''14. Department of Veterans Affairs;'' in section 3(b); and

(b) renumbering all subsequent subsections in section 3(b) appropriately.

Sec. 17. Those elements of the Department of Homeland Security that are supervised by the Department's Under Secretary for Information Analysis and Infrastructure Protection through the Department's Assistant Secretary for Information Analysis, with the exception of those functions that involve no analysis of foreign intelligence information, are designated as elements of the Intelligence Community under section 201(h) of the Homeland Security Act of 2002 and section 3(4) of the National Security Act of 1947, as amended (50 U.S.C. 401a).

Sec. 18. Executive Order 12333 of December 4, 1981 (''United States Intelligence Activities''), is amended in Part 3.4(f) by:

(a) striking ''and'' at the end of subpart 3.4(f)(6);

(b) striking the period and inserting ''; and'' at the end of subpart 3.4(f)(7); and

(c) adding a new subpart 3.4(f)(8) to read as follows: ''(8) Those elements of the Department of Homeland Security that are supervised by the Department's Under Secretary for Information Analysis and Infrastructure Protection through the Department's Assistant Secretary for Information Analysis, with the exception of those functions that involve no analysis of foreign intelligence information.''

Sec. 19. *Functions of Certain Officials in the Department of Homeland Security.*

The Secretary of Homeland Security, the Deputy Secretary of Homeland Security, the Under Secretary for Information Analysis and Infrastructure Protection, Department of Homeland Security, and the Assistant Secretary for Information Analysis, Department of Homeland Security, each shall be considered a ''Senior Official of the Intelligence Community'' for purposes of Executive Order 12333, and all other relevant authorities, and shall:

(a) recognize and give effect to all current clearances for access to classified information held by those who become employees of the Department of Homeland Security by operation of law pursuant to the Homeland Security Act of 2002 or by Presidential appointment;

(b) recognize and give effect to all current clearances for access to classified information held by those in the private sector with whom employees of the Department of Homeland Security may seek to interact in the discharge of their homeland security-related responsibilities;

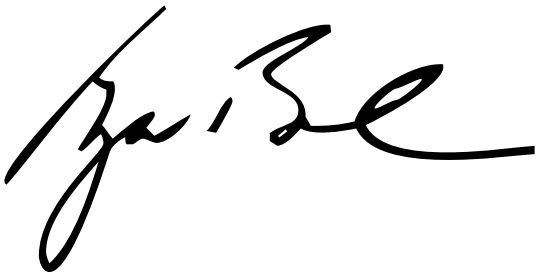
(c) make all clearance and access determinations pursuant to Executive Order 12968 of August 2, 1995, or any successor Executive Order, as to employees of, and applicants for employment in, the Department of Homeland Security who do not then hold a current clearance for access to classified information; and

(d) ensure all clearance and access determinations for those in the private sector with whom employees of the Department of Homeland Security may seek to interact in the discharge of their homeland security-related responsibilities are made in accordance with Executive Order 12829 of January 6, 1993.

Sec. 20. Pursuant to the provisions of section 1.4 of Executive Order 12958 of April 17, 1995 (''Classified National Security Information''), I hereby authorize the Secretary of Homeland Security to classify information originally as ''Top Secret.'' Any delegation of this authority shall be in accordance with section 1.4 of that order or any successor Executive Orders.

Sec. 21. This order shall become effective on January 24, 2003.

Sec. 22. This order does not create any right or benefit, substantive or procedural, enforceable at law or equity, against the United States, its departments, agencies, or other entities, its officers or employees, or any other person.



THE WHITE HOUSE,
January 23, 2003.

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Rules and Regulations

Federal Register

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Tuesday, January 28, 2003

This section of the FEDERAL REGISTER contains regulatory documents having general applicability and legal effect, most of which are keyed to and codified in the Code of Federal Regulations, which is published under 50 titles pursuant to 44 U.S.C. 1510.

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DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 989

[Docket No. FV03–989–1 IFR]

Raisins Produced From Grapes Grown in California; Modifications to the Raisin Diversion Program

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Interim final rule with request for comments.

SUMMARY: This rule modifies the requirements of the raisin diversion program (RDP) authorized under the Federal marketing order for California raisins (order). The order regulates the handling of raisins produced from grapes grown in California and is administered locally by the Raisin Administrative Committee (RAC). The changes are intended to provide the RAC with additional flexibility when implementing a RDP, and provide opportunity for all producers to participate in a program. The changes include adding an additional date by which the RAC can increase the tonnage allotted to a RDP; adding authority for the RAC to limit the amount of tonnage allotted to vine removal; modifying the application of the production cap for spur pruners under a RDP; adding authority for the RAC to condition a vine removal program with a producer's agreement not to replant and to compensate the RAC for damages if replanting occurs; revising the requirements for prioritizing and allocating tonnage for spur pruners under a RDP; allowing partial production units to be included in a RDP and adding authority for the RAC to specify provisions to maintain the integrity of the program; and specifying in the regulations the approval of a program's provisions by the Department.

DATES: Effective: January 29, 2003. Comments received by March 31, 2003, will be considered prior to issuance of a final rule.

ADDRESSES: Interested persons are invited to submit written comments concerning this rule. Comments must be sent to the Docket Clerk, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue SW, STOP 0237, Washington, DC 20250–0237; Fax: (202) 720–8938, or e-mail: *moab.docketclerk@usda.gov.* All comments should reference the docket number and the date and page number of this issue of the **Federal Register** and will be made available for public inspection in the Office of the Docket Clerk during regular business hours, or can be viewed at: *http://www.ams.usda.gov/fv/moab.html.*

FOR FURTHER INFORMATION CONTACT: Maureen T. Pello, Senior Marketing Specialist, California Marketing Field Office, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 2202 Monterey Street, suite 102B, Fresno, California 93721; telephone: (559) 487–5901, Fax: (559) 487–5906; or Ronald L. Cioffi, Chief, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue SW, STOP 0237, Washington, DC 20250–0237; telephone: (202) 720–2491, Fax: (202) 720–8938.

Small businesses may request information on complying with this regulation by contacting Jay Guerber, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue SW, STOP 0237, Washington, DC 20250–0237; telephone: (202) 720–2491, Fax: (202) 720–8938, or e-mail: *Jay.Guerber@usda.gov.*

SUPPLEMENTARY INFORMATION: This rule is issued under Marketing Agreement and Order No. 989 (7 CFR part 989), both as amended, regulating the handling of raisins produced from grapes grown in California, hereinafter referred to as the ''order.'' The order is effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), hereinafter referred to as the ''Act.''

The Department of Agriculture (USDA) is issuing this rule in conformance with Executive Order 12866.

This rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule is not intended to have retroactive effect. This rule will not preempt any State or local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule.

The Act provides that administrative proceedings must be exhausted before parties may file suit in court. Under section 608c(15)(A) of the Act, any handler subject to an order may file with USDA a petition stating that the order, any provision of the order, or any obligation imposed in connection with the order is not in accordance with law and request a modification of the order or to be exempted therefrom. Such handler is afforded the opportunity for a hearing on the petition. After the hearing USDA would rule on the petition. The Act provides that the district court of the United States in any district in which the handler is an inhabitant, or has his or her principal place of business, has jurisdiction to review USDA's ruling on the petition, provided an action is filed not later than 20 days after the date of the entry of the ruling.

This rule modifies the administrative rules and regulations regarding the RDP specified under the order. The changes are designed to provide the RAC with additional flexibility when implementing a RDP, and provide the opportunity for all producers to participate in a program. The changes are as follows: Add an additional date by which the RAC can increase the tonnage allotted to a RDP; add authority for the RAC to limit the amount of tonnage allocated for vine removal; modify application of the production cap for spur pruners under a RDP; adding authority for the RAC to condition a vine removal program with a producer's agreement not to replant and to compensate the RAC for damages if replanting occurs; revise the requirements for prioritizing and allocating tonnage for spur pruners under a RDP; and allow partial production units to be included in a RDP and allow the RAC to specify provisions to maintain the integrity of the program.

These regulatory changes were recommended by the RAC at meetings on October 15, and December 12, 2002, by a near unanimous vote. A member voting no expressed concern with the definition of partial production unit as proposed by the RAC.

Given the above changes, appropriate revisions are made to the text of § 989.156 to include specific references to approval of USDA for a program's provisions.

Volume Regulation Provisions

The order provides authority for volume regulation designed to promote orderly marketing conditions, stabilize prices and supplies, and improve producer returns. When volume regulation is in effect, a certain percentage of the California raisin crop may be sold by handlers to any market (free tonnage) while the remaining percentage must be held by handlers in a reserve pool (reserve) for the account of the RAC. Reserve raisins are disposed of through various programs authorized under the order. For example, reserve raisins may be sold by the RAC to handlers for free use or to replace part of the free tonnage they exported; carried over as a hedge against a short crop the following year; or may be disposed of in other outlets not competitive with those for free tonnage raisins, such as government purchase, distilleries, or animal feed. Net proceeds from sales of reserve raisins are ultimately distributed to reserve pool equity holders.

Raisin Diversion Program

The RDP is another program concerning reserve raisins authorized under the order and may be used, as a means for bringing supplies into closer balance with market needs. Authority for the program is provided in § 989.56 of the order. Paragraph (e) of that section provides authority for the RAC to establish, with the approval of USDA, such rules and regulations as may be necessary for the implementation and operation of a RDP. Accordingly, additional procedures and deadlines are specified in § 989.156.

Pursuant to these sections, the RAC must meet during the crop year to review raisin data, including information on production, supplies, market demand, and inventories. If the RAC determines that the available supply of raisins, including those in the reserve pool, exceeds projected market needs, it can decide to implement a diversion program, and announce the amount of tonnage eligible for diversion during the subsequent crop year. Producers who wish to participate in the RDP must submit an application to the RAC. Under the current regulations, the RAC conducts a lottery if the tonnage applied for exceeds what has been allotted. RAC staff then notifies producers whether they have been accepted into the program.

Approved producers curtail their production by vine removal or some other means established by the RAC. Such producers receive a certificate the following fall from the RAC which represents the quantity of raisins diverted. Producers sell these certificates to handlers who pay producers for the free tonnage applicable to the diversion certificate minus the established harvest cost for the diverted tonnage. Handlers redeem the certificates by presenting them to the RAC, and paying an amount equal to the established harvest cost plus payment for receiving, storing, fumigating, handling, and inspecting the tonnage represented on the certificate. The RAC then gives the handler raisins from the prior year's reserve pool in an amount equal to the tonnage represented on the diversion certificate. The new crop year's volume regulation percentages are applied to the diversion tonnage acquired by the handler, as if the handler had bought raisins directly from a producer.

RAC Recommendation

The California raisin and grape industries continue to be plagued by burdensome supplies and severe economic conditions. Industry members have been reviewing various options to help address some of these concerns. The RAC also has been reviewing options to help the industry address these issues through the marketing order. The RAC proposed some requirements for a 2003 RDP at a meeting on October 15, 2002. Additional revisions were proposed by the RAC's Executive Committee on October 24, and November 4 and 26, 2002. The RAC met on December 12, 2002, to review the Executive Committee's changes and proposed program. The RAC ultimately recommended specific changes to the order's regulations regarding the RDP that could apply to any future RDP. The changes are designed to provide the RAC with additional flexibility when implementing a RDP, and provide opportunity for all producers to participate in a program. The changes are described in the following paragraphs.

Additional Date for Increasing the RDP Tonnage

With the exception of the 2002–03 crop year, § 989.56(a) of the order and § 989.156(a)(1) of the regulations specify that the RAC must announce the quantity of tonnage allotted to a RDP on or before November 30 of each crop year. Section 989.156(a)(1) specifies further, with the exception of the 2002–03 crop year, that the RAC may announce an increase in the tonnage eligible for a RDP on or before January 15 of each crop year. The November 30-deadline in the order was suspended, and the November 30 and January 15 dates in the regulations were extended for the 2002–03 crop year to dates specified by the RAC (67 FR 71072; November 29, 2002) to allow time for review and modification of the RAC's proposed RDP changes.

The RAC recommended that the regulations be modified to allow the RAC an additional opportunity to increase the tonnage eligible for a RDP on or before May 1 of each crop year subsequent to 2002–03. This will allow the RAC the opportunity to allocate additional tonnage to a RDP in years when raisin deliveries may be slow, or when additional reserve raisins may be available later during the crop year. Section 989.156(a)(1) is modified accordingly.

Limit on Tonnage Allocated for Vine Removal

Section 989.156(h)(1) specifies that the RAC may limit a RDP to vine removal only. This requirement will remain unchanged by this rule. However, the RAC proposed having the ability to cap, or limit, the amount of tonnage allocated to a RDP for vine removal. For example, the RAC may allocate 100,000 tons to a RDP, of which 50,000 tons would be allotted for vine removal only. Under this scenario, the remaining 50,000 tons would be available for spur pruners (or producers who opted to reduce their production by methods other than vine removal). As described later in this rule, the RAC recommended revising the regulations to allow for the allocation of tonnage to spur pruners pro rata to all who applied. Imposing a cap on vine removers would ensure that a certain amount of tonnage would be available for a spur prune program. This additional requirement is specified in § 989.156(a)(2).

Additional Agreement for Vine Removers Who Replant

This RAC recommended that authority be added for the RAC to condition a vine removal program with

a producer's agreement not to replant and to compensate the RAC for damages if replanting occurs. Producers who agree to remove vines, but replant within a specified number of years (maximum of 5 crop years), as determined by the RAC, with the approval of USDA, must agree to compensate the RAC for appropriate damages for the tonnage specified in the applicable diversion certificate. The payment of damages would be appropriate because replanting would cause serious damage to a RDP and the raisin industry. The RAC contemplates that a 5-year restriction on replanting would be included as a feature of a 2003 RDP for NS raisins. This would remove acreage from production for at least 8 crop years because it takes about 3 years for a new vineyard to have significant production. Adding this requirement to a RDP is expected to help the industry reduce its burdensome oversupply.

Accordingly, the producer application for a 2003 RDP has been modified to condition a vine removal program with a producer's agreement not to replant. Producers who elect to participate in a RDP and later replant will be required to compensate the RAC for damages at a rate per ton to be determined by the RAC and approved by USDA for the tonnage specified on the diversion certificate. Funds collected by the RAC for such damages will be deposited in the reserve pool applicable to the particular diversion program and be distributed to the equity holders in that pool. If a determination is made by the Committee that a producer violated the agreement not to replant and is subject to damages, the producer may appeal the Committee's decision in accordance with paragraph (m) of § 989.156.

Application of Production Cap

Under a RDP, the reserve tonnage allocated to a program becomes part of the following year's supply. For example, if 100,000 tons of 2002–03 reserve raisins were allocated to a RDP, that tonnage would be issued to RDP producers in the fall of 2003 in the form of certificates from the RAC. The certificates represent actual raisins. The 100,000 tons would then be included in the 2003–04 crop estimate. A higher crop estimate reduces the free tonnage percentage. Since producers are paid by handlers for their free tonnage raisins, a lower free tonnage percentage reduces producer returns. The industry has had concerns with the impact of large diversion programs on the following year's free tonnage percentage.

As a result, the RAC recommended that the concern about large RDP's adversely impacting the following year's free tonnage percentage be addressed through application of the production cap. A production cap is a limit on the yield per acre that is permitted under a RDP. Section 989.56(a) specifies that the RAC must announce the production cap at the same time it announces a RDP for the crop year. The section specifies further that the production cap shall equal 2.75 tons per acre, unless it is lowered by the RAC, with approval of the Secretary.

The RAC proposed that it have the flexibility to limit the production cap to a percentage of the yield per acre for production units on which producers agree to spur prune (or curtail production by methods other than vine removal) to lessen the adverse effects a large RDP would have on the following year's free tonnage percentage. For example, the RAC could specify that the production cap applicable to 2003 spur pruners would equal the lesser of 2.75 tons per acre, or 80 percent of the 2002 yield per acre on that production unit. The following table illustrates this further.

2002 yield per acre (tons	Application of production cap (tons)
5.0	2.75 (2.75 cap)
4.0	2.75 (2.75 cap)
3.5	2.75 (2.75 cap)
3.4375	2.75 (both 80% and 2.75)
3.2	2.56 (80% cap)
3.0	2.4 (80% cap)
2.5	2.0 (80% cap)
2.0	1.6 (80% cap)
1.5	1.2 (80% cap)
1.0	0.8 (80% cap)

Participants who agree to remove vines would not be subject to the percentage limit on the production cap because of the effectiveness of vine removal in reducing production capacity. However, such participants would remain subject to the established production cap. This additional flexibility is specified in § 989.156(a)(2).

Allocation of Tonnage for Spur Pruners (Includes Methods of Diversion Other Than Vine Removal)

Section 989.156(d) currently requires that, if reserve tonnage exists after the allocation of diversion tonnage has been made to all eligible producer applicants who agree to remove vines, a lottery shall be held to allocate remaining tonnage. The RAC recommended that it have the flexibility to allocate such tonnage either pro rata to remaining applicants or by a lottery for complete production units to remaining applicants if a minimal amount of tonnage remains. Allocating tonnage pro rata would provide the opportunity for all producers to participate in a spur prune program. Accordingly, §§ 989.156(a)(2) and 989.156(d) is modified to incorporate this option.

Inclusion of Partial Production Units

As described above, the RAC contemplates future RDP's where the tonnage allotted to applicants who agree to spur prune vines (or divert production using a method other than vine removal) may be done on a pro rata basis. Such producers would remove only a portion of a production unit, or a ''partial'' unit.

In 1997, the RAC recommended that partial production units no longer be accepted into the RDP, and § 989.156 was modified accordingly (62 FR 60764; November 13, 1997). This action was taken because the RAC had concerns that some producers were removing weak vines in a production unit and getting credit under a RDP for an inflated amount of tonnage.

To implement the RAC's proposal for allocating tonnage on a pro-rata basis to applicants who agree to spur prune their vines, and help maintain integrity of the program, the RAC recommended that a partial production unit must have two permanent, contiguous (natural or man-made) boundaries. This would eliminate the ability for producers to select certain rows of weak vines and artificially inflate the tonnage on their unit. This definition is added to paragraph (o) of § 989.156. Additionally, the words ''or portion thereof'' are added to paragraphs (h) and (i) of § 989.156 to indicate that partial units may be included in a RDP.

Finally, the RAC recommended that it be given the authority to specify provisions for a partial production unit to maintain the integrity of the program. For example, the RAC indicated that it might want to specify that only a certain corner of each vineyard may be accepted into a spur-prune RDP to further alleviate the problem of a producer choosing the weakest corner of his/her vineyard, and to help maintain the integrity of the RDP. Accordingly, paragraph (a) of § 989.156 is modified to reflect that the RAC may limit a program that is applicable to partial production units by specifying the portion of the production units that can be diverted, or like provisions to maintain the integrity of the program.

Initial Regulatory Flexibility Analysis

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA), the Agricultural Marketing Service (AMS) has considered the economic impact of this action on small entities.

Accordingly, AMS has prepared this initial regulatory flexibility analysis.

The purpose of the RFA is to fit regulatory actions to the scale of business subject to such actions in order that small businesses will not be unduly or disproportionately burdened. Marketing orders issued pursuant to the Act, and rules issued thereunder, are unique in that they are brought about through group action of essentially small entities acting on their own behalf. Thus, both statutes have small entity orientation and compatibility.

There are approximately 20 handlers of California raisins who are subject to regulation under the order and approximately 4,500 raisin producers in the regulated area. Small agricultural firms are defined by the Small Business Administration (13 CFR 121.201) as those having annual receipts of less that $5,000,000, and small agricultural producers are defined as those having annual receipts of less than $750,000. Thirteen of the 20 handlers subject to regulation have annual sales estimated to be at least $5,000,000, and the remaining 7 handlers have sales less than $5,000,000. No more than 7 handlers, and a majority of producers, of California raisins may be classified as small entities.

The California Agriculture Statistics Service (CASS) has forecast the 2002 production of raisin variety grapes at 2,550,000 tons (green). This is a relatively high level of production. The record high production occurred in 2000, at 2,921,000 tons (green).

Producers market raisin variety grapes in the fresh market (table), wine or juice market (crush), or dry them into raisins. Typically, 67 percent of the crop is dried for raisins, 20 percent crushed for wine and juice, and the remaining 13 percent of the crop is utilized in fresh and canned sales. These outlets provide a hedge for producers attempting to minimize risk from bad weather (rain) or a depressed market (concentrate, wine, or raisins).

The industry's estimate for all variety raisin production, as of October 4, 2002, is 446,449 dried tons (407,996 tons for NS). This will be the third consecutive year that raisin production has been above 400,000 tons. Combined domestic and export demand (shipments) is estimated at approximately 300,000 tons. These levels of production, combined with stable demand have resulted in a large build-up of free and reserve carryin inventories.

The RAC reports that 48,749 tons of NS raisins are currently being held in the reserve pool from the 2001 crop. In addition, 153,152 free tons are held by handlers in inventories. With current total dried production estimated at 446,449 tons, and combined free and reserve inventories at 201,901 tons, the industry has over 600,000 tons of raisins.

This type of surplus situation leads to serious marketing problems. Handlers compete against each other in an attempt to sell more raisins to reduce inventories and to market their crop. This situation puts downward pressure on producers' prices and incomes.

In addition, it has been reported that the wineries offered $65 a ton for green NS raisins for crushing. In recent years, wineries have typically offered prices ranging from $164 to $200 per ton. The wine price for NS grapes was lowered to $125 per ton in 2000 and fell to $85.70 per ton in 2001. This has resulted in more raisin variety grapes being dried for raisins, which has added to the surplus situation in the raisin market.

Typically, 500,000 tons of raisin variety grapes are delivered to the wineries for crushing. In 2001, this volume decreased to 261,000 tons. The 2002 crop year deliveries for crushing are expected to remain low.

Surplus situations are often the result of increased bearing acres, which are encouraged by high prices. However, bearing acres for raisin variety grapes have fallen from 280,000 acres in 2000 to 273,000 acres in 2002. In addition, 27,000 acres were idle due to the raisin diversion program. The increased raisin production is largely the result of producers deciding to dry more grapes for raisins due to the low crush prices and increased yields. The RAC hopes to utilize the RDP to help alleviate the industry's oversupply. The RAC's recommended changes are designed to add flexibilities to the RDP, and provide the opportunity for all producers to participate in a program. The overall impact of a RDP with the recommended flexibility is expected to impact small and large entities positively by reducing the industry's production capacity, and by bringing supplies in closer balance with market needs.

This rule revises § 989.156 of the order's rules and regulations regarding the RDP. Under a RDP, producers receive certificates from the RAC for curtailing their production to reduce burdensome supplies. The certificates represent diverted tonnage. Producers sell the certificates to handlers who, in turn, redeem the certificates with the RAC for raisins from the prior year's reserve pool. Specifically, this rule revises the requirements of a RDP to: Add an additional date by which the RAC can increase the tonnage allotted to a RDP; add authority for the RAC to limit the amount of tonnage allocated for vine removal; modify application of the production cap for spur pruners under a RDP; adding authority for the RAC to condition a vine removal program with a producer's agreement not to replant and to compensate the RAC for damages if replanting occurs; revise the requirements for prioritizing and allocating tonnage for spur pruners under a RDP; allow partial production units to be included in a RDP and add authority for the RAC to specify provisions to maintain the integrity of the program; and specifying in the regulations the approval of a RDP's provisions by USDA. Authority for these changes is provided in § 989.56(e) of the order.

Regarding the impact of this action on affected entities, these changes are designed to provide the RAC with additional flexibility when implementing a RDP. Adding the May 1 date whereby the RAC may increase the tonnage allotted to a RDP would give more producers an opportunity to participate in the program. The changes regarding the way tonnages are allocated under a program (cap on vine removal that would allow a specified amount of tonnage available for spur pruners, and allocating spur prune tonnage pro rata to all applicants) are intended to provide the opportunity for all producers to participate at some level in a RDP. Thus, all producers could potentially have the opportunity to earn some income for curtailing their production.

With regard to cost, based on past RDP's, the RAC estimates that compliance and verification costs associated with a RDP average about $150 per production unit. Using an estimate of 1.25 production units per RDP producer application, if all 4,500 producers participated in a RDP, there could potentially be about 5,625 production units in a program. Thus, using the $150 per unit figure, compliance and verification costs for the program could average about $843,750. The overall impact of the changes is difficult to quantify. However, if a RDP implemented using the increased flexibility helps bring supplies into balance with market needs over time, the benefits for both small and large entities would be positive. When supplies and market needs are in balance, experience has shown that producers and handlers both benefit, regardless of size.

Regarding alternatives to the RAC's recommendation, the industry has been considering various options and programs to help alleviate the severe economic conditions adversely

impacting both raisin producers and handlers. Industry groups outside of the RAC are seeking financial assistance under section 32 of the Act of August 24, 1935 (7 U.S.C. 612c). The RAC also has a subcommittee that is reviewing long-term solutions to help the industry that would require formal rulemaking changes to the marketing order. RAC members have been seeking short-term solutions available through the existing order, or slight modifications thereto. Thus, the RAC recommended changes are designed to add flexibilities to the RDP and provide the potential for all producers to participate in a program. The RAC hopes to utilize the RDP to help alleviate the industry's oversupply situation.

The RAC and Executive Committee did consider options to some of the features recommended by the RAC. One option concerned an alternative to application of the production cap. That is, specifying that producers who agreed to spur prune their vines would have to spur prune an additional percentage of their acreage that would not be reflected on their diversion certificates. However, the order does not provide authority for the application of a ''multiplier'' in this fashion to vineyards that were spur pruned. The RAC ultimately proposed that it have the flexibility to limit the production cap to a percentage of the yield per acre for production units on which producers agree to spur prune (or curtail production by methods other than vine removal).

At its meetings, the Executive Committee also considered other dates besides May 1 whereby the RAC could increase the tonnage allotted to a RDP. An April date was contemplated, but not proposed because industry members would rather be past the threat of an April frost before making a decision whether to add tonnage to a RDP. Thus, the May 1 date was deemed appropriate and ultimately proposed by the RAC.

There was some discussion by industry members about partial production units. Some members questioned whether authority for partial units should be added back into the order's regulations, and some questioned whether a partial unit should be required to have two permanent, contiguous boundaries. There was also concern that a producer could spur prune a corner of his/her vineyard, redesign his/her trellacing system to provide for significantly increased yields, and contribute to future oversupplies. After much discussion, the majority of RAC members concurred with allowing partial production units in a RDP, and limiting such a unit to one that has two permanent, contiguous boundaries.

This rule does not add measurably to the current burden on reporting or recordkeeping requirements for either small or large raisin handlers. In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35), the information collection requirement referred to in this rule (*i.e.*, the RDP application) has been approved by the Office of Management and Budget (OMB) under OMB Control No. 0581–0178. As with all Federal marketing order programs, reports and forms are periodically reviewed to reduce information requirements and duplication by industry and public sector agencies. Finally, USDA has not identified any relevant Federal rules that duplicate, overlap, or conflict with this rule.

Further, this action was reviewed by the RAC's Administrative Issues Subcommittee October 7 and 15, and December 10 and 12, 2002, by the RAC's Executive Committee on October 24, and November 4 and 26, 2002, and by the RAC on October 7 and 15, and December 12, 2002. All of these meetings where this action was deliberated were public meetings widely publicized throughout the raisin industry. All interested persons were invited to attend the meetings and participate in the industry's deliberations. Finally, all interested persons are invited to submit information on the regulatory and informational impact of this action on small businesses.

A small business guide on complying with fruit, vegetable, and specialty crop marketing agreements and orders may be viewed at: *http://www.ams.usda.gov/fv/moab.html.* Any questions about the compliance guide should be sent to Jay Guerber at the previously mentioned address in the **FOR FURTHER INFORMATION CONTACT** section.

A 60-day comment period is provided to allow interested persons to respond to this rule. Any comments received will be considered prior to finalization of this rule.

After consideration of all relevant material presented, including the RAC's recommendation, and other information, it is found that this interim final rule, as hereinafter set forth, will tend to effectuate the declared policy of the Act.

Pursuant to 5 U.S.C. 553, it is also found and determined upon good cause that it is impracticable, unnecessary, and contrary to the public interest to give preliminary notice prior to putting this rule into effect, and that good cause exists for not postponing the effective date of this rule until 30 days after publication in the **Federal Register** because: (1) This rule provides the RAC with additional flexibility when implementing a RDP; (2) this rule needs to be in place as soon as possible so that these requirements can be in place for a 2003 RDP, and the RAC and all potential participants can plan accordingly. (3) this action was recommended by a near unanimous vote of the RAC and producer participation in a RDP is voluntary; and (4) a 60-day comment period is provided and all comments received will be considered in finalizing this rule.

List of Subjects in 7 CFR Part 989

Grapes, Marketing agreements, Raisins, Reporting and recordkeeping requirements.

For the reasons set forth in the preamble, 7 CFR part 989 is amended as follows:

PART 989—RAISINS PRODUCED FROM GRAPES GROWN IN CALIFORNIA

1. The authority citation for 7 CFR part 989 continues to read as follows:

Authority: 7 U.S.C. 601–674.

2. In § 989.156, paragraphs (a), (d), (h)(2) and (3), (i), and (o) are revised to read as follows:

§ 989.156 Raisin diversion program.

(a)(1) *Quantity to be diverted.*

On or before November 30 of each crop year, the Committee, with the approval of the Secretary, shall announce the quantity of raisins eligible for a raisin diversion program: *Provided,* That, for the 2003 diversion program, this date may be extended by the Committee to a later date within the 2002–03 crop year. On or before January 15 of each crop year, the Committee, with the approval the Secretary, may announce an increase in the tonnage eligible for a raisin diversion program: *Provided,* That, for the 2002 Natural (sun-dried) Seedless raisin diversion program, the Committee may announce an increase in the quantity of tonnage eligible for the program later than January 15: *And provided further,* That, for the 2003 and subsequent raisin diversion programs, the Committee, with the approval of the Secretary, may announce an increase in the tonnage eligible for a raisin diversion program on or before May 1 of each crop year. The quantity eligible for diversion may be announced for any of the following varietal types of raisins: Natural (sun-dried) Seedless, Muscat (including other raisins with seeds), Sultana, Zante

Currant, Monukka, and Other Seedless raisins. At the same time, the Committee, with the approval of the Secretary, shall determine and announce to producers, handlers, and the cooperative bargaining association(s) the allowable harvest cost to be applicable to such diversion tonnage. The factors to be reviewed by the Committee in determining allowable harvest costs shall include but not be limited to: Costs for picking, turning, rolling, boxing, paper trays, vineyard terracing, hauling to the handler, and crop insurance.

(2) *Additional provisions.*

For any crop year's diversion program, the Committee, with the approval of the Secretary, may:

(i) Limit the entire program to production units on which producers agree to remove vines;

(ii) Limit a portion of the program to production units on which producers agree to remove vines;

(iii) Limit the production cap to a percentage (less than or equal to 100 percent) of the yield per acre of the specific production unit for production units on which producers agree to divert production by methods other than vine removal;

(iv) Limit participation in a vine removal program to producer's who agree not to replant vines for a period not to exceed 5 years and who agree to compensate the Committee for appropriate damages if vines are replanted. Damages collected by the Committee pursuant to this subparagraph shall be deposited in the reserve pool fund of the reserve pool applicable to the particular diversion program and be distributed to the equity holders in that pool. If a determination is made by the Committee that a producer violated the agreement not to replant and is subject to damages, the producer may appeal the Committee's decision in accordance with paragraph (m) of this section;

(v) Specify how tonnage available to producers who agree to divert production by means other than through vine removal will be allotted, either pro-rata to remaining applicants, or by lottery to remaining applicants for complete production units if a minimal amount of tonnage remains; and/or

(vi) Limit a program that is applicable to partial production units by specifying the portion of the production units that can be diverted, or like provisions to maintain the integrity of the program.

Additional provisions provided pursuant to this paragraph shall be announced at the time the tonnage available for that season's diversion program is announced.

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(d) *Priority of applications and allocation of tonnage.*

(1) Those producer applications indicating that the vines on the producing units will be removed shall receive first priority over other applications when reserve tonnage under the program is to be allocated.

(2) Pursuant to paragraphs (a)(2)(i) and (a)(2)(ii) of this section, if the entire program, or a portion of the program, is limited to production units on which producers agree to remove vines, and the production volume in such vine removal applications exceeds the amount of diversion tonnage available for vine removal, a lottery will be held to allocate such vine removal tonnage among the respective applicants.

(3) Remaining tonnage available under a diversion program, after that allocated to producer applications indicating that the vines of the producing units will be removed, shall be allocated by the Committee either:

(i) pro-rata to remaining applicants; or

(ii) to remaining applicants by a lottery for complete production units, if a minimal amount of tonnage remains.

In conducting any lottery under this section, the Committee may group producer applications on a handler-by-handler basis, and separate lotteries will be held for each group. The diversion tonnage of raisins available for each such group in each lottery may not exceed the percentage of total handler acquisitions acquired by the group's handler during the previous crop year. If diversion tonnage exists after such group lotteries, such remaining diversion tonnage may be allocated by one lottery of all remaining producer applications.

* * * * *

(h) * * *

(2) *Period of diversion.* An approved applicant must remove the grapes, or vines, indicated on the application within the production unit, or portion thereof, designated within the application not later than June 1 of the crop year in which a diversion program is implemented. Producers who remove the vines on a production unit after August 15 may qualify for a diversion program for that crop year if a diversion program is announced and if diversion on that unit and vine removal after August 15 can be documented and verified.

(3) *Failure to divert.* Any raisin producer who does not take the necessary measures to remove the grapes on an approved production unit, or portion thereof, by June 1, or any raisin producer who has indicated the removal of vines or the intent to remove the vines and who does not remove such vines on an approved production unit by June 1, shall not be issued a diversion certificate, may be subject to liquidated damages and interest charges as provided in paragraph (q) of this section, may be subject to an injunctive action under the Act, and may be denied the opportunity to participate in the next diversion program, when implemented: *Provided:* That any producer who has more than one production unit and fails to divert on an approved production unit or portion thereof may be denied the opportunity to participate on all of that producer's production units, in the next diversion program. For spur-pruned vines, this date may be extended 2 weeks from the date of the inspection of a producer's vineyard if more than 4 bunches on spur-pruned vines are present at the time of inspection.

(i) *Issuance of certificates.* When preliminary percentages are announced, the Committee shall issue diversion certificates to those approved applicants who have removed grapes in accordance with this section. Such certificates shall represent an amount of reserve tonnage raisins equal to the amount of raisins diverted from the production unit(s), or portion(s) thereof, specified in the producer application, or additional quantity granted by the Committee when vines are diverted through vine removal or any other means established by the Committee, with the approval of the Secretary. If, prior to issuance of a certificate, the Committee is notified by an approved applicant that such applicant's interest in the production unit(s), or portion(s) thereof, involved in the program has been transferred to another person, the Committee may substitute the transferee for the applicant provided the transferee agrees to comply with the provisions of this section.

* * * * *

(o) *Production units.*

(1) For the purpose of the raisin diversion program, a production unit is a clearly defined geographic area with permanent boundaries (either natural or man-made). A producer must be able to document to the Committee the previous year's production data for that specific area by means of sales receipts or other deliveries or transfer documents which indicate the creditable fruit weight delivered to handlers from that specific area. If the information submitted by producers on the application concerning a unit's

production is significantly greater than past production on the unit, production on neighboring units, or the industry norm, or the production is unable to be verified based on submitted documentation, the Committee may request additional documentation such as tray count, payroll records, prior years' production, and insurance records to substantiate the tonnage of raisins produced on all production units that such applicant controls or owns. Producers would not be precluded from submitting other information substantiating production if those producers desired. A new production unit will not be eligible for the raisin diversion program until at least 1 year's production has been grown and is documented. An existing production unit, transferred to a new or expanding producer, is eligible for the raisin diversion program as soon as the previous year's production can be properly documented.

(2) For purposes of the raisin diversion program, a partial production unit must have two permanent, contiguous boundaries (either natural or man-made).

* * * * *

Dated: January 23, 2003.

A.J. Yates,

Administrator, Agricultural Marketing Service.

[FR Doc. 03–1965 Filed 1–23–03; 5:09 pm]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 989

[Docket No. FV02–989–5 FIR]

Raisins Produced From Grapes Grown in California; Additional Opportunity for Participation in 2002 Raisin Diversion Program

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: The Department of Agriculture (USDA) is adopting, as a final rule, with change, an interim final rule that allowed producers an additional opportunity to participate in the 2002 raisin diversion program (RDP). The RDP is authorized under the Federal marketing order for California raisins (order). The order regulates the handling of raisins produced from grapes grown in California and is administered locally by the Raisin Administrative Committee (RAC). This action was intended to help reduce the burdensome oversupply affecting the California raisin industry.

EFFECTIVE DATE: January 29, 2003.

FOR FURTHER INFORMATION CONTACT: Maureen T. Pello, Senior Marketing Specialist, California Marketing Field Office, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 2202 Monterey Street, suite 102B, Fresno, California 93721; telephone: (559) 487–5901, Fax: (559) 487–5906; or George Kelhart, Technical Advisor, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue SW, STOP 0237, Washington, DC 20250–0237; telephone: (202) 720–2491, Fax: (202) 720–8938.

Small businesses may request information on complying with this regulation by contacting Jay Guerber, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue SW, STOP 0237, Washington, DC 20250–0237; telephone: (202) 720–2491, Fax: (202) 720–8938, or e-mail: *Jay.Guerber@usda.gov.*

SUPPLEMENTARY INFORMATION: This rule is issued under Marketing Agreement and Order No. 989 (7 CFR part 989), both as amended, regulating the handling of raisins produced from grapes grown in California, hereinafter referred to as the ''order.'' The order is effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), hereinafter referred to as the ''Act.''

USDA is issuing this rule in conformance with Executive Order 12866.

This rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule is not intended to have retroactive effect. This rule will not preempt any State or local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule.

The Act provides that administrative proceedings must be exhausted before parties may file suit in court. Under section 608c(15)(A) of the Act, any handler subject to an order may file with USDA a petition stating that the order, any provision of the order, or any obligation imposed in connection with the order is not in accordance with law and request a modification of the order or to be exempted therefrom. A handler is afforded the opportunity for a hearing on the petition. After the hearing USDA would rule on the petition. The Act provides that the district court of the United States in any district in which the handler is an inhabitant, or has his or her principal place of business, has jurisdiction to review USDA's ruling on the petition, provided an action is filed not later than 20 days after the date of the entry of the ruling.

A 2002 RDP for Natural (sun-dried) Seedless (NS) raisins was established in November 2001. A total of 54,086 tons of 2001 crop reserve raisins was allocated to the program. This rule continues in effect a rule that allowed producers an additional opportunity to participate in the 2002 RDP. An additional 25,000 tons of 2001 crop reserve raisins was allocated to the RDP. The additional program applied to producers who agreed to remove vines from production, and was intended to help the industry reduce its burdensome oversupply. The action was recommended by the RAC at a meeting on May 30, 2002, by a vote of 45 in favor, 1 opposed (member opposed because the program did not provide for a moratorium on replanting), and 1 abstained.

Volume Regulation Provisions

The order provides authority for volume regulation designed to promote orderly marketing conditions, stabilize prices and supplies, and improve producer returns. When volume regulation is in effect, a certain percentage of the California raisin crop may be sold by handlers to any market (free tonnage) while the remaining percentage must be held by handlers in a reserve pool (reserve) for the account of the RAC. Reserve raisins are disposed of through various programs authorized under the order. For example, reserve raisins may be sold by the RAC to handlers for free use or to replace part of the free tonnage they exported; carried over as a hedge against a short crop the following year; or may be disposed of in other outlets not competitive with those for free tonnage raisins, such as government purchase, distilleries, or animal feed. Net proceeds from sales of reserve raisins are ultimately distributed to producers.

Raisin Diversion Program

The RDP is another program concerning reserve raisins authorized under the order and may be used as a means for controlling overproduction. Authority for the program is provided in § 989.56 of the order. Paragraph (e) of that section provides authority for the RAC to establish, with the approval of USDA, such rules and regulations as may be necessary for the implementation and operation of a RDP. Accordingly, additional procedures are specified in § 989.156.

Pursuant to these sections, the RAC must meet each crop year to review raisin data, including information on production, supplies, market demand, and inventories. If the RAC determines that the available supply of raisins, including those in the reserve pool, exceeds projected market needs, it can decide to implement a diversion program, and announce the amount of tonnage eligible for diversion during the subsequent crop year. Producers wishing to participate in the RDP must submit an application to the RAC. The RAC conducts a lottery if the tonnage applied for exceeds what has been allotted. RAC staff then notifies producers whether they have been accepted into the program.

Approved producers curtail their production by vine removal or some other means established by the RAC. Such producers receive a certificate the following fall from the RAC which represents the quantity of raisins diverted. Producers sell these certificates to handlers who pay producers for the free tonnage applicable to the diversion certificate minus the established harvest cost for the diverted tonnage. Handlers redeem the certificates by presenting them to the RAC and paying an amount equal to the established harvest cost plus payment for receiving, storing, fumigating, handling, and inspecting the tonnage represented on the certificate. The RAC then gives the handler raisins from the prior year's reserve pool in an amount equal to the tonnage represented on the diversion certificate. The new crop year's volume regulation percentages are applied to the diversion tonnage acquired by the handler (as if the handler had bought raisins directly from a producer).

Initial 2002 NS Diversion Program

On November 28, 2001, the RAC met and reviewed data relating to the quantity of reserve raisins and anticipated market needs. With a 2001–02 NS crop estimated at 359,341 tons, and a computed trade demand (comparable to market needs) of 235,850 tons, the RAC projected a reserve pool of 123,491 tons of NS raisins. With such a large anticipated reserve, the RAC announced that 45,182 tons of NS raisins would be eligible for diversion under the initial 2002 RDP. The RAC increased this amount to 54,086 tons at a meeting on January 11, 2002.

Of the 54,086 tons, 49,086 tons were made available to approved producers who submitted applications to the RAC by December 20, 2001, with producers who planned to remove vines receiving priority over those who planned to curtail (abort) production through spur pruning or other means. Section 989.156(d) requires the RAC to give priority to applicants who agree to remove vines. Another 5,000 tons were made available to approved producers who submitted applications to the RAC from December 21, 2001, through May 1, 2002, and planned to remove vines. Authority for this additional opportunity for vine removal is provided in § 989.156(s).

Harvest costs for the initial RDP were announced by the RAC at $340 per ton, and a production cap of 2.0 tons per acre was established for the program. The production cap limits the yield per acre that a producer can claim. The 2.0-ton per acre production cap was established in an interim final rule that was published in the **Federal Register** on March 15, 2002 (67 FR 11555). A final rule was published on May 14, 2002 (67 FR 34383).

Under the initial RDP, the RAC received applications from producers accounting for 40,788 tons of raisins that would be removed from production by spur pruning vines, and 7,704 tons of raisins that would be removed from production by removing vines. Using the production cap of 2.0 tons per acre, about 3,850 acres should be removed from production through vine removal (7,704 tons divided by 2.0 tons per acre). The following is a summary of the tonnage allocated and participation in the initial 2002 RDP:

INITIAL 2002 RDP

	Allotted tonnage	Applications from producers
Dec. 20 Deadline	49,086 tons (vine removal and spur prune, with priority for vine removal).	40,788 tons (spur prune); 6,896 tons (vine removal)
May 1 Deadline	5,000 tons (vine removal only)	808 tons (vine removal).
Total	54,086 tons	40,788 tons (spur prune); 7,704 tons (vine removal).

RAC Recommendation

The RAC met on May 30, 2002, and recommended adding an additional opportunity for producers to participate in the 2002 NS RDP in view of the oversupply situation affecting the California raisin industry. Specifically, the RAC allocated an additional 25,000 tons of 2001 NS reserve raisins to the program. The additional program applied to producers who agreed to remove vines, and included a bonus for participating producers. Producers received a diversion certificate from the RAC equal to 1.5 times the creditable fruit weight of the raisins produced on the production unit (up to a maximum of 3 tons per acre). For example, if an applicant's verified production was 1.7 tons per acre, the applicant received credit for 2.55 tons per acre (1.7 tons times 1.5). If an applicant's verified production was 2.5 tons per acre, the applicant received credit for 3.0 tons per acre (2.0 tons times 1.5). Authority for the RAC to issue diversion certificates in an amount greater than the creditable fruit weight produced on the production unit is provided in § 989.56(c) of the order. The bonus was intended to encourage participation in the program.

The additional opportunity to participate in the 2002 RDP was available to producers who did not participate in the initial 2002 program (''new participants''), and to approved participants in the initial 2002 RDP who curtailed their production by spur pruning their vines (''early season spur pruners''). Producers wishing to participate in the program had to file an application with the RAC by July 8, 2002. Priority was given to new participants. If the production applied for had exceeded the 25,000 tons added to the program, a lottery would have been held to allocate the tonnage among the applicants, pursuant to applicable procedures specified in § 989.156(d). Under the additional opportunity program, the RAC received applications from producers accounting for an estimated 2,265 acres and 5,920 tons of raisins that would be removed from production by removing vines.

Harvest costs for the additional opportunity program for ''early season spur pruners'' remained at $340 per ton, while harvest costs for new participants were $100 per ton. Because harvest costs are deducted from the payment producers receive from handlers for their diversion certificates, a reduction

in harvest costs results in a larger payment to producers for the certificates. The reduction in harvest costs for new participants and resulting increased payment was intended to take into account in producing a 2002 crop up to time of removal. the the cultural and some harvest costs incurred by such producers.

Under the additional opportunity program, vines had to either be removed, or chain sawed at the base by July 31, 2002. RAC staff verified that the vines had been removed or adequately chain sawed. RAC staff later re-inspected vines that had been chain sawed to ensure that the remainder of the vine had been removed.

Accordingly, a new paragraph (u) was added to § 989.156 specifying the provisions of the additional opportunity program with applicable time frames. In addition, necessary conforming changes were made to paragraphs (a), (q), and (s) of § 989.156.

The interim final rule stated that, when redeeming certificates for 2001 raisin handlers would pay the RAC the harvest cost plus payment for bins and for receiving, storing, fumigating, and handling the reserve raisins. The Committee believed that RDP certificates should be treated like ''raisins'', and handlers should pay the same as if they had to buy raisins directly from producers. Bin rental is included in the cost of raisins bought directly from producers and the Committee believed that this cost should be included in the cost of raisins bought through the RDP. The bin payment was set at $20. However, some Committee members believed that this fee contributed to handler delays/reluctance in buying 2001 RDP certificates for 2000–01 reserve pool raisins from producers. To avoid this in purchasing 2002 RDP certificates for 2001–02 reserve pool raisins, the Committee on August 14, 2002, unanimously voted to waive the $20 per ton bin fee.

Final Regulatory Flexibility Analysis

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA), the Agricultural Marketing Service (AMS) has considered the economic impact of this action on small entities. Accordingly, AMS has prepared this final regulatory flexibility analysis.

The purpose of the RFA is to fit regulatory actions to the scale of business subject to such actions in order that small businesses will not be unduly or disproportionately burdened. Marketing orders issued pursuant to the Act, and rules issued thereunder, are unique in that they are brought about through group action of essentially small entities acting on their own behalf. Thus, both statutes have small entity orientation and compatibility.

There are approximately 20 handlers of California raisins who are subject to regulation under the order and approximately 4,500 raisin producers in the regulated area.

Small agricultural firms are defined by the Small Business Administration (13 CFR 121.201) as those having annual receipts of less that $5,000,000, and small agricultural producers are defined as those having annual receipts of less than $750,000. Thirteen of the 20 handlers subject to regulation have annual sales estimated to be at least $5,000,000, and the remaining 7 handlers have sales less than $5,000,000. No more than 7 handlers, and a majority of producers, of California raisins may be classified as small entities.

This rule continues to revise § 989.156 of the order's rules and regulations regarding the RDP. Under a RDP, producers receive certificates from the RAC for curtailing their production to reduce burdensome supplies. The certificates represent diverted tonnage. Producers sell the certificates to handlers who, in turn, redeem the certificates with the RAC for raisins from the prior year's reserve pool. A 2002 RDP for NS raisins was established in November 2001, and 54,086 tons of 2001 crop reserve raisins were allocated to the program. This rule continues in effect a rule that allowed producers an additional opportunity to participate in the 2002 RDP in view of the oversupply situation affecting the California raisin industry. An additional 25,000 tons of 2001 crop reserve raisins was allocated to the RDP. The additional program applied to producers who agreed to remove vines from production, and was intended to help the industry reduce its burdensome oversupply. Under the program, the RAC received applications from producers accounting for an estimated 2,265 acres, and 5,920 tons of raisins that would be removed from production. Authority for this action is provided in § 989.56(e) of the order.

Regarding the impact of this action on affected entities, the additional opportunity program was intended to help the industry as a whole reduce its burdensome oversupply. The California raisin industry has experienced successive crop years of high production. The 10-year average for deliveries of NS raisins to handlers is 344,303 tons. NS raisin deliveries for the 2000 crop year were 432,616 tons, and deliveries for the 2001 crop year were 377,328 tons. As previously stated, the initial RDP removed about 3,850 acres from production. It is estimated that the additional opportunity program removed another 2,265 acres from production, for a combined total of about 6,115 acres, which helped the industry reduce its oversupply.

Regarding the impact of this action on producers, the program provided producers an additional opportunity to earn some income for removing their vineyards from production. Participating producers received a bonus for removing their vines. They received a diversion certificate from the RAC equal to 1.5 times the creditable fruit weight of the raisins produced on the production unit (up to a maximum of 3 tons per acre). Producers will sell their certificates to handlers and be paid for the free tonnage applicable to the diversion certificate minus the harvest cost for the diverted tonnage. Applicable harvest costs for the additional RDP were announced by the RAC at $100 per ton for ''new participants'' (producers who did not participate in the initial 2002 RDP), and $340 per ton for ''early season spur pruners'' (approved participants in the initial 2002 RDP who curtailed production by spur pruning their vines).

Regarding the impact on handlers, handlers will redeem certificates for 2001 crop NS raisins and pay the RAC the applicable harvest cost ($100 per ton for new vine pull participants, and $340 per ton for early season spur pruners) plus and for receiving, storing, fumigating, handling ($46 per ton), and inspecting ($9.00 per ton). The program will return $155 per ton for new participant certificates, and $395 per ton for remaining certificates to the 2001 NS reserve pool. A bin fee, which has been one of the charges has been dropped because of delays in purchases of RDP certificates. Such income to the reserve pool could be used to pay remaining pool expenses or be distributed to 2001 NS reserve pool equity holders (producers). Thus, all such equity holders could potentially benefit from this action.

Several alternatives to the recommended action were considered by the RAC. There was discussion at the meeting regarding whether the program should include a moratorium on replanting. At the time, there was no authority for a moratorium on replanting. Some members expressed concern that producers may remove their vines and replant with new systems that produce higher yields, thereby contributing to more oversupply. At the time, there was no authority for a moratorium on replanting.

There was some discussion at the meeting about the impact of adding an additional 25,000 tons of 2001 crop NS reserve raisins to the 2002 supply. Through the order's mathematical formula for volume regulation, additional 2002 supply will reduce the 2002 free tonnage percentage. This could reduce returns for producers since producers are paid a field price for the free tonnage percentage of their crop. There was some consideration of allowing handlers to redeem a portion of their certificates for 2001 reserve raisins and a portion for 2002 crop reserve raisins. However, the current order only provides authority for handlers to redeem certificates for reserve raisins from the prior crop year.

There was also discussion at the meeting about giving smaller producers some priority in the program. For example, the program could have allowed 2 days for producers with production units of 80 acres to apply, and then the program could have been opened up to other applicants. However, this was not recommended over a program providing the same opportunity to all eligible producers.

This rule does not measurably add to the current burden on reporting or recordkeeping requirements for either small or large raisin handlers. In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35), the information collection requirement referred to in this rule (*i.e.*, the RDP application) has been approved previously by the Office of Management and Budget (OMB) under OMB Control No. 0581–0178. As with all Federal marketing order programs, reports and forms are periodically reviewed to reduce information requirements and duplication by industry and public sector agencies. Finally, USDA has not identified any relevant Federal rules that duplicate, overlap, or conflict with this rule.

Further, the RAC's meeting on May 30, 2002, where this action was deliberated was a public meeting widely publicized throughout the raisin industry. All interested persons were invited to attend the meeting and participate in the industry's deliberations.

A small business guide on complying with fruit, vegetable, and specialty crop marketing agreements and orders may be viewed at: *http://www.ams.usda.gov/fv/moab.html.* Any questions about the compliance guide should be sent to Jay Guerber at the previously mentioned address in the **FOR FURTHER INFORMATION CONTACT** section.

Additionally, the interim final rule published in the **Federal Register** on June 24, 2002 (67 FR 42471) inadvertently omitted the last three sentences in the regulatory text in paragraph (a)(1) of § 989.156. Those sentences were included in another interim final rule published on November 29, 2002 (67 FR 71072). The November 2002 interim final rule made additional revisions to paragraphs (a) and (s) of § 989.156 as they originally appeared in the June 2002 interim final rule.

Committee staff mailed copies of the interim final rule to all Committee members and alternates, the Raisin Bargaining Association, handlers and dehydrators. In addition, the rule was made available through the Internet by the Office of the Federal Register and USDA. That rule provided for a 15-day comment period that ended on July 9, 2002. Five comments were received.

A raisin producer who had participated in the early season RDP and curtailed production by removing vines wanted to be compensated at the same rate as producers under the late season RDP, and another wanted to receive the 1.5 ton bonus for each ton of creditable fruit weight removed. Under the early season RDP, harvest costs were announced by the RAC at $340 per ton, a production cap of 2.0 tons per acre was established for the program, and producers received a diversion certificate from the RAC equal to the creditable fruit weight removed (up to a maximum of 2 tons per acre). Under the late season RDP, for vine removal only, producers received a diversion certificate from the RAC equal to 1.5 times the creditable fruit weight of the raisins produced on the production unit removed (up to a maximum of 3 tons per acre). This bonus was included as a condition of the late season RDP to encourage more vine removals. This was a reasonable addition given the industry's excess production capacity, and the oversupply situation currently burdening the industry.

In addition, harvest costs for the late season program were $100 per ton where new participants were involved and $340 in the case of ''early season spur pruners'' who decided to remove vines under the late season program. Because harvest costs are deducted from the payment producers receive from handlers for their diversion certificates, a reduction in harvest costs results in a larger payment to producers for the certificates. As already mentioned, the reduction in harvest costs for new participants and resulting increased payment was intended to take into account the cultural and some harvest costs incurred by such producers in producing a 2002 crop up to the time of removal.

Two letters each signed by two raisin producers, who also handle raisins, were submitted by their attorney. These commenters opposed the late season RDP.

They contend that this program will harm the industry, that it lacks economic merit, and that it conflicts with both the letter and spirit of the raisin marketing order.

They stated that their equity in the 2001 reserve pool (the pool from which handlers purchasing RDP certificates will obtain raisins) will be reduced severely because of USDA's agreement to sell 2001 reserve pool raisins to farmers for $100 per ton at the rate of 3 tons per acre (the conditions of the late season RDP) versus $340 per ton at the rate of 2 tons per acre under the early season RDP. The commenters point out that § 989.67(d)(1) of raisin marketing order requires reserve tonnage raisins to be sold to handlers at prices and in a manner intended to maximize producer returns and achieve maximum disposition of such raisins by the time reserve tonnage raisins from the subsequent crop year are available.

Under the early season RDP, producers curtailing production through vine removal or other approved means received a diversion certificate equal to the quantity of raisins diverted up to a maximum of 2 tons per acre. Handlers purchasing certificates will pay the producer for the free tonnage applicable to the diversion certificate minus a $340 per ton harvest cost for the diverted tonnage. New participants in the late season RDP received a diversion certificate equal to 1.5 times the tonnage diverted (up to a maximum of 3 tons per acre). Authority to issue diversion certificates in an amount greater than the creditable fruit weight produced on the production unit is specified in paragraph (c) of § 989.56. In this case, handlers will pay the producer for the free tonnage applicable to the diversion certificate for the diverted tonnage minus the $100 per ton harvest cost fixed for late season RDP harvest costs. This means that producers selling diversion certificates with the $100 per ton harvest cost will receive more money per ton than those selling certificates with the $340 per ton cost. The reduced harvest costs for late season RDP participants were intended to recognize the cultural and some harvest costs such producers incurred in producing a 2002 crop up to the time of removal. This difference in payments is reasonable for this program.

The amount of money per ton generated for 2001 reserve pool equity

holders from the late season RDP for new participants would be $155 per ton, and $395 per ton for early season RDP participants, and early season spur pruners who decided to remove vines during the late season RDP. Handlers will redeem certificates for 2001 NS raisins and pay RAC the applicable harvest cost ($100 per ton for new participants, and $340 per ton for early season spur pruners and vine removers) plus payment for receiving, storing, fumigating, handling ($46 per ton), and inspecting ($9 per ton).

The difference between the two amounts for 2001 reserve pool equity holders is $240 per ton. This reduction in returns to the 2001 reserve pool equity holders from the new participant late season RDP versus the early season RDP participants and early season spur pruners who decided to remove vines during the late season RDP was considered by RAC and determined to be reasonable under the circumstances. Under the late season RDP, RAC received applications from producers accounting for an estimated 2,265 acres and 5,920 tons of raisins that would be removed from production by removing vines. The RAC had approved 25,000 tons for this program.

Moreover, some in the industry believe that vine removals are needed now, rather than later, to start bringing production more closely in line with market needs. As the two producer/handlers stated, the industry needs to remove permanently 100,000 acres over time to align production with current market needs.

The two producer/handlers also mentioned that the reserve is supposed to fulfill the ''orderly marketing'' objective of the Act and marketing order by being available in case the new crop is substantially reduced by drought or post-harvest rain. They state that the 2001 crop reserve raisins could be worth much more in the event California were to experience a disastrous heat wave prior to or disastrous rain during harvest. Because of this, these two commenters ask USDA not to allow the RAC to implement a program (under the guise of reducing long-run supply) that risks market chaos and unreasonable fluctuations in supplies and prices. They state that it is improper to use the marketing order tools to protect a massive over-production situation from normal corrective market forces, especially when all of the cost of this waste falls on the existing equity holders in the 2001 reserve pool. However, the late season RDP was intended to assist in bringing supplies into closer balance with demand, and as such, was a proper use of this marketing order tool.

These commenters also allege that the late season RDP is intended to support a handler's plan to finance improved trellis systems and per acre yields, and would encourage marginal producers to stay in the raisin business by helping to finance their transition to upgraded trellis systems that will nearly double existing per-acre yields. They contend that this program will even be more devastating to traditional raisin producers if producers who intended to sell fresh grapes into the winery or as table grapes participate in the late season RDP.

The two producer/handlers further contend that the industry's productive capacity will naturally decline overtime without the RDP program. The RAC's primary goal in recommending the late season vine removal RDP was to speedup and facilitate needed production capacity reductions. Given the industry's poor economic condition, and difficulties many in the industry are experiencing in obtaining operating funds from lending institutions, wholesale replanting on land from which grape vines have been removed under the RDP by current raisin producers, non-traditional raisin producers such as winery and table grape producers, and other investors outside the raisin industry would appear unlikely.

The two producer/handlers also believe that vine removal without at least a 5-year moratorium on replanting grape vines on that acreage will not be successful. The current supply and marketing problems, and financial difficulties facing the industry, may lessen interest in replanting the acreage from which vines have been removed with new grape varieties. Further, there is no authority for a replanting moratorium in the 2002 Raisin Diversion Program.

These commenters also suggested that USDA convene an industry summit to explore the various economic issues facing the California raisin industry. USDA stands ready to assist the industry in improving the marketing order and marketing order operations, and helping the industry overcome its current oversupply and financial problems.

Taking into account the forgoing, USDA continues to be of the view that the late season RDP as reflected in this action is consistent with the provisions of the marketing order and the Act.

A final comment was received from an official of a lending institution that has an extensive portfolio of agricultural loans for various commodities, including raisins, in California. The commenter urged the RAC and USDA to make changes to the RDP vine removal application to adequately protect lenders in any vine removal or diversion program. According to the commenter, the current terms and conditions do not go far enough in ensuring that the producer applicant informs the lender of the producers planned participation. The commenter requested that such changes be made as soon as possible, but recognized that it was too late to implement such changes for the 2002 RDP.

Section 989.156(b) describes the application that producers must complete and submit to the RAC to participate in a RDP. The current application procedures, among other things, indicate that the producer's application must state that all persons with an equity interest in the raisins produced from the grapes grown on the production unit identified on the application must consent to the filing of the application. As mentioned before, the representative of an association of lending institutions believed that the current requirement of obtaining consent from all persons having an equity interest in the raisins produced from grapes grown on the production unit identified did not go far enough in protecting the interests of lending institutions. The commenter mentioned that the lending institution might not have an equity interest in the raisins produced, but might have an equity interest in the vines on the production unit on which the grapes were produced, or the land, as security for the loan.

To address the commenter's concern and further clarify the application process, the certification has been broadened to assure that all such persons are given an opportunity to consent to the producer's participation in the RDP. Section 989.156(b) is modified accordingly.

The modification to the RDP application has no additional impact on producers and handlers. It simply requires producers to certify that all persons with an equity interest in the raisins, vines, or land on which the grapes were produced have been given the opportunity to consent to the producer's participation in the RDP.

After consideration of all relevant material presented, including the information and recommendations submitted by the RAC, the comments received, and other available information, it is hereby found that this rule, as hereinafter set forth, will tend to effectuate the declared policy of the Act.

Pursuant to 5 U.S.C. 553, it is also found and determined that good cause exists for not postponing the effective date of this rule until 30 days after publication in the **Federal Register** because the 2002 Raisin Diversion Program is well underway and this action should be made effective as soon as possible.

List of Subjects in 7 CFR Part 989

Grapes, Marketing agreements, Raisins, Reporting and recordkeeping requirements.

PART 989—RAISINS PRODUCED FROM GRAPES GROWN IN CALIFORNIA

Accordingly, the interim final rule amending 7 CFR part 989 which was published at 67 FR 42471 on June 24, 2002, is adopted as a final rule with the following change:

1. The authority citation for 7 CFR part 989 continues to read as follows:

Authority: 7 U.S.C. 601–674.

2. In § 989.156, paragraph (b)(6) is revised as follows:

989.156 Raisin diversion program.

* * * * *

(b) * * *

(6) A statement that all persons with an equity interest in the grapes in the production unit to be diverted, in the vines, or the land on which the grapes were produced consent to the filing of the application.

* * * * *

Dated: January 23, 2003.

A.J. Yates,

Administrator, Agricultural Marketing Service.

[FR Doc. 03–1964 Filed 1–23–03; 5:09 pm]

BILLING CODE 3410–02–P

DEPARTMENT OF JUSTICE

Immigration and Naturalization Service

8 CFR Part 286

[INS No. 2180–01]

RIN 1115–AG47

Establishment of a $3 Immigration User Fee for Certain Commercial Vessel Passengers Previously Exempt

AGENCY: Immigration and Naturalization Service, Justice.

ACTION: Final rule.

SUMMARY: This rule amends the Immigration and Naturalization Service (Service) regulations, as required by law, to provide for the collection of a $3 fee for commercial vessel passengers previously exempt under section 286(e)(1) of the Immigration and Nationality Act (Act), other than passengers on Great Lakes ferries and other Great Lakes vessels. This rule amends the Service regulations to require certain commercial vessel operators or their ticketing agents to charge and collect a $3 user fee from every commercial vessel passenger whose journey originated in the United States, Canada, Mexico, a territory or possession of the United States, or an adjacent island except those individuals exempted under section 286(e) of the Act.

DATES: This final rule is effective February 27, 2003.

FOR FURTHER INFORMATION CONTACT: Penny Pastiva, Border Management Branch, Office of Budget, Immigration and Naturalization Service, 425 I Street, NW., Room 5236, Washington, DC 20536, telephone (202) 514–6254.

SUPPLEMENTARY INFORMATION:

Authority To Collect an Immigration User Fee

In the 1987 Appropriations Act for the Department of Justice, Public Law 99–591, Congress directed the Service beginning in fiscal year (FY) 1987 to collect an immigration user fee for each passenger arriving in the United States by commercial air or sea conveyance (with limited exceptions). As provided by law, in section 286 of the Act, the user fees that are collected may be used, among other things, to:

- Provide immigration inspection and preinspection services for commercial aircraft and vessels;
- Provide overtime immigration inspection services for commercial aircraft or vessels;
- Administer debt recovery, including the establishment and operation of a national collections office;
- Expand, operate, and maintain information systems for nonimmigrant control and debt collection;
- Detect fraudulent documents used by passengers traveling to the United States, including training of, and technical assistance to, commercial airline and vessel personnel regarding such detection;
- Provide detention and removal services for inadmissible aliens arriving on commercial aircraft and vessels and for any inadmissible alien who has attempted illegal entry into the United States through avoidance of immigration inspection at air or sea ports-of-entry; and,
- Administer removal and asylum screening proceedings at air or sea ports-of-entry for inadmissible aliens arriving on commercial aircraft and vessels, including immigration removal proceedings resulting from the presentation of fraudulent documents and the failure to present documentation and for any inadmissible alien who has attempted illegal entry into the United States by avoiding immigration inspection at air or sea ports-of-entry.

Requirement To Charge a $3 Inspection Fee

In section 109 of the Department of Justice Appropriations Act, 2002, Public Law 107–77, title I, enacted on November 28, 2001, Congress amended section 286(e) of the Act to authorize the Attorney General to charge and collect a user fee from certain previously-exempt commercial vessel passengers. Prior to the enactment of this law, commercial vessel passengers whose journeys originated in Canada, Mexico, a State, territory or possession of the United States, or an adjacent island, were statutorily exempt from paying the Immigration User Fee prescribed by section 286(d) of the Act. While these vessel passengers were exempt from paying the fee, the Service was still required to provide inspection services. This exemption resulted in the Service's inability to invest in necessary staffing and technology resources. The new fee will enhance inspection operations and related inspection activities that support seaport immigration inspection.

Section 202 of chapter 2, title I of the 2002 Supplemental Appropriations Act for Further Recovery From and Response to Terrorist Attacks on the United States, Public Law 107–206, signed August 2, 2002, amended section 286(e)(3) of the Act to remove any discretionary authority not to collect the fee from commercial vessel passengers otherwise covered by the provision (principally, by changing ''The Attorney General is authorized to charge and collect'' to AThe Attorney General shall charge and collect'').

Comments on the Service's Proposed Rule Implementing Section 286(e)(3) of the Act

The Service published a proposed rule in the **Federal Register** on April 3, 2002, at 67 FR 15753, authorizing the collection of a $3 fee for certain commercial vessel passengers previously exempt under section 286(e)(1) of the Act. The proposed rule was published with a 30-day comment period, which closed on May 3, 2002. On May 14, 2002, the Service reopened

the comment period until May 28, 2002 (67 FR 34414).

The Service received a total of 36 comments on the proposed rule. Comments were received from a broad spectrum of individuals and organizations, including 7 ferry and cruise ship companies, 3 transportation advocacy groups, 5 city and county groups, 3 elected officials, 2 port authorities, 1 tourism board, and 15 interested individuals. All the comments were carefully considered before preparing this final rule. The following is a discussion of these comments and the Service's response.

1. Applicability to Ferries

The primary concerns expressed in the comments received all related to international ferry operations in the Pacific Northwest. All comments received on this subject were similar and made three main arguments: (1) There is no justification for imposing this fee on ferries of the Pacific Northwest while excluding the Great Lakes ferries; (2) the $3 fee represents a disproportionately high percentage of the cost of using a ferry in the State of Washington; and (3) the $3 fee will have a negative economic impact on the international ferry operators in the Pacific Northwest and on related businesses in the tourism industry. One commenter, the Airports Council International—North America, strongly supported implementation of the $3 fee for commercial vessel passengers.

The justification for excluding Great Lakes ferries and other Great Lakes vessels in the proposed rule was simple: Congress itself made special provisions for the Great Lakes by specifically exempting Great Lakes vessels from the authorization in section 286(e)(3) of the Act. Furthermore, the recent amendment to section 286(e)(3) of the Act removes whatever discretion the Service might have had to make exceptions for commercial vessel passengers other than the Great Lakes exception, including on the basis of economic impact. Because the amendment in the 2002 Supplemental Appropriations Act provides that the Attorney General ''shall'' charge this fee, the Service is required to adhere to the terms of the statutory language, which limited exceptions to the Great Lakes vessels and ferries. Therefore, the final rule applies to any commercial vessel (as defined in the Service's existing regulations at 8 CFR 286.1(d) to include ''any civilian vessel being used to transport persons or property for compensation or hire'') other than the Great Lakes vessels.

One commenter requested the Service make this rule effective for ferries sometime beyond the 30 days after date of publication effective date for other vessels in order to give ferry operators additional time to comply. The Service considered this comment but declined to make a special exception for ferries regarding the effective date of this rule.

2. Collection of the Fee

In addition to the ferry-specific concerns about the impact discussed above, there were other concerns expressed in the comments about the effective date when the $3 fee would be collected, and the amount of the fee collected.

In order to clarify the fee collection requirement, the Service has amended § 286.2(b) to make clear that the $3 fee will be assessed based on bookings or reservations made on or after February 27, 2003. By using the booking date, the cruise line or other commercial vessel operator can accurately communicate to passengers both the cost of the passage and the applicable fees for which they are responsible. This provides clear guidance on when fee collections are due and results in an ease of administration for operators whose passengers will be subject to the $3 fee.

Regarding the amount of the fee, the Service notes that it has been set by law, and the FY 2002 Supplemental Appropriation Act requires the collection of the $3 fee for certain commercial vessel passengers who were previously exempt, except for the Great Lakes exception provided by Congress.

3. Other Changes

Finally, the Service has made minor stylistic corrections to the proposed rule's changes to 8 CFR 286.3(a).

Regulatory Flexibility Act

The Commissioner of the Immigration and Naturalization Service, in accordance with the Regulatory Flexibility Act (5 U.S.C. 605(b)), has reviewed this regulation and by approving it certifies that this rule will not have a significant economic impact on a substantial number of small entities. Immigration user fees are already being collected by commercial vessel carriers and/or their ticketing agents in connection with voyages originating in areas already covered by the fee. Since the passengers rather than the carriers ultimately pay the immigration inspection user fee, these passengers are not considered small entities as that term is defined in 5 U.S.C. 601(6), and this rule does not have a significant economic impact upon a substantial number of small entities.

Unfunded Mandates Reform Act of 1995

This rule will not 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, and it will not significantly or uniquely affect small governments. Therefore, no actions were deemed necessary under the provisions of the Unfunded Mandates Reform Act of 1995.

Small Business Regulatory Enforcement Fairness Act of 1996

This rule is not a major rule as defined by section 804 of the Small Business Regulatory Enforcement Act of 1996. This rule will not result in an annual effect on the economy of $100 million or more; a major increase in cost or prices; or significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based companies to compete with foreign-based companies in domestic and export markets.

Executive Order 12866

This rule is considered by the Department of Justice, Immigration and Naturalization Service, to be a ''significant regulatory action'' under Executive Order 12866, section 3(f), Regulatory Planning and Review. Accordingly, this regulation has been submitted to the Office of Management and Budget for review.

1. Impact of the $3 fee on cruise ships generally. The Service estimates that approximately 8 million cruise ship passengers per year who were previously statutorily exempt from paying the Immigration User Fee will now be required to pay this fee. The Service therefore estimates that the Immigration User Fund will receive $24 million in additional revenue per year from the fees paid by these passengers. The imposition of the $3 statutory fee is not anticipated to result in an economic burden for the cruise ship industry. When compared to the price of the average cruise, the $3 fee is very small and is not expected to affect cruise booking decisions.

2. Impact of the $3 fee on ferries. The $3 immigration inspection fee imposed by this rule is likely to impose a greater proportionate burden on the service provided by ferry operators (in areas other than the statutorily-exempted Great Lakes areas) because the $3 fee is larger in relation to the cost of a ferry ticket as compared to a cruise ship

ticket. The Service has been informed that the $3 fee could increase the price of an adult ticket for a ferry in Washington State by an average of 20 to 25 percent, with larger percentage increases for lower-priced child and infant tickets. Commenters feared a significant loss of ferry business due to the imposition of this fee, in some cases possibly causing operators to drop seasonal international service.

The Service estimates that one million passengers enter into the United States per year using Pacific Northwest ferries. If passenger volume after the imposition of the $3 fee were to remain constant, the Service's Immigration User Fund could receive as much as $3 million annually from ferry passengers. However, based on comments received, the Service expects that the imposition of the $3 fee will result in a decrease in the number of ferry passengers, as travelers switch to alternative transportation modes. Accordingly, the Service is unable to estimate the amount that will actually be collected.

While the Service is sympathetic to arguments presented by commenters concerned about the likely disproportionate impact of this $3 fee on ferry passengers, it has no discretion under the statute to provide any exemption, waiver, or other accommodation to ferries other than for the Great Lakes ferries, which Congress exempted by law.

3. Benefits of this rule. For years, the Service has been providing the immigration inspection services for commercial vessel operators (including ferries) on voyages originating in the United States, Canada, Mexico, a territory or possession of the United States, or an adjacent island, but has not—until the statutory change being implemented by this rule—been able to charge commercial vessel passengers the immigration user fee for doing so. These services are described further in the Supplementary Information for this rule. The $3 fee is appropriate to offset the costs of seaport inspection services provided, allows for the investment in new resources towards improving the inspection process at seaports, and allows the Service to meet customer service requirements. These services and activities funded by the immigration user fee benefit the national security by screening arriving aliens for possible threats and also benefit the general public by complementing other immigration enforcement activities and speed the processing of legitimate travelers.

Executive Order 13132

This rule 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 section 6 of Executive Order 13132, it is determined that this rule does not have sufficient federalism implications to warrant the preparation of a federalism summary impact statement.

Executive Order 12988 Civil Justice Reform

This rule meets the applicable standards set forth in sections 3(a) and 3(b)(2) of Executive Order 12988.

Paperwork Reduction Act

Under the Paperwork Reduction Act of 1995, Pub. L. 104–13, all Departments are required to submit to the Office of Management and Budget (OMB), for review and approval, any reporting requirements inherent in a final rule. This rule does not impose any new reporting or recordkeeping requirements under the Paperwork Reduction Act.

List of Subjects in 8 CFR Part 286

Air carriers, Immigration, Maritime carriers, Reporting and recordkeeping requirements.

Accordingly, part 286 of chapter I of title 8 of the Code of Federal Regulations is amended as follows:

PART 286—IMMIGRATION USER FEE

1. The authority citation for part 286 continues to read as follows:

Authority: 8 U.S.C. 1103, 1356; 8 CFR part 2.

2. Section 286.2 is amended by redesignating paragraph (b) as paragraph (c), and by adding a new paragraph (b), to read as follows:

§ 286.2 Fee for arrival of passengers aboard commercial aircraft or commercial vessels.

* * * * *

(b) A fee, in the amount prescribed in section 286(e)(3) of the Act, per individual, is charged and collected by the Commissioner for the immigration inspection at a port-of-entry in the United States, or for the preinspection in a place outside the United States of each commercial vessel passenger whose journey originated in the United States, Canada, Mexico, territories or possessions of the United States, or adjacent islands, except as provided in § 286.3. All tickets or documents for transportation on voyages that are booked on or after February 27, 2003, will be subject to this immigration user fee.

* * * * *

3. Section 286.3 is amended by revising the introductory text, and by revising paragraph (a), to read as follows:

§ 286.3 Exceptions.

The fees set forth in § § 286.2(a) and 286.2(b) shall not be charged or collected from passengers who fall within any one of the following categories:

(a) Persons arriving at designated ports-of-entry by the following vessels, when operating on a regular schedule: Great Lakes international ferries or Great Lakes vessels on the Great Lakes and connecting waterways;

* * * * *

Dated: December 26, 2002.

Michael J. Garcia,

Acting Commissioner, Immigration and Naturalization Service.

[FR Doc. 03–1808 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–10–P

FEDERAL RESERVE SYSTEM

12 CFR Part 208

[Regulation H; Docket No. R–1129]

Reporting and Disclosure Requirements for State Member Banks With Securities Registered Under the Securities Exchange Act of 1934

AGENCY: Board of Governors of the Federal Reserve System.

ACTION: Final rule.

SUMMARY: The Board has adopted a final rule to reflect the amendments made to section 12(i) of the Securities Exchange Act of 1934 by the Sarbanes-Oxley Act of 2002. These amendments vest the Board with the authority to administer and enforce several of the enhanced reporting, disclosure and corporate governance obligations imposed by the Sarbanes-Oxley Act with respect to state member banks that have a class of securities registered under the Securities Exchange Act of 1934.

DATES: The final rule is effective on April 1, 2003.

FOR FURTHER INFORMATION CONTACT: Kieran J. Fallon, Senior Counsel (202–452–5270), or Walter R. McEwen, Counsel (202–452–3321), Legal Division; Terrill Garrison, Supervisory Financial Analyst (202–452–2712), Division of Banking Supervision and

Regulation. Users of Telecommunication Device for Deaf (TTD) *only,* call (202) 263–4869.

SUPPLEMENTARY INFORMATION:

Background

Section 12(i) of the Securities Exchange Act (15 U.S.C. 78*l*(i)) (Exchange Act) vests the Board with the authority to administer and enforce the disclosure and reporting requirements of sections 12, 13, 14(a), 14(c), 14(d), 14(f) and 16 of the Exchange Act with respect to state member banks that have a class of securities registered under section 12(b) or 12(g) of the Exchange Act (registered banks).[1] Section 208.36 of the Board's Regulation H (12 CFR part 208.36) implements the reporting and disclosure provisions of sections 12, 13, 14(a), 14(c), 14(d), 14(f) and 16 of the Exchange Act for registered banks. As a general matter, Regulation H requires registered banks to comply with the rules, regulations and forms adopted by the Securities and Exchange Commission (SEC) under sections 12, 13, 14(a), 14(c), 14(d), 14(f) and 16 of the Exchange Act, but requires registered banks to file any reports or forms required by such regulations with the Board (rather than the SEC) and substitutes the ''Board'' for the ''SEC'' each place that term appears in the SEC's rules and forms.

On July 30, 2002, President Bush signed into law the Sarbanes-Oxley Act of 2002.[2] Titles III and IV of the Sarbanes-Oxley Act include a number of provisions that are designed to improve the corporate governance and financial disclosures of issuers that have a class of securities registered under sections 12(b) or 12(g) of the Exchange Act, or that are required to file periodic reports with the SEC under section 15(d) of the Exchange Act (public companies). The Sarbanes-Oxley Act also amended section 12(i) of the Exchange Act to vest the Board with the authority to administer and enforce sections 302, 303, 304, 306(a), 401(b), 404, 406 and 407 of the Sarbanes-Oxley Act, as well as section 10A(m) of the Exchange Act (as added by section 301 of the Sarbanes-Oxley Act), with respect to registered banks.[3]

Summary of Interim Rule

In September 2002, the Board adopted on an interim basis, and requested public comment on, an amendment to section 208.36 of Regulation H to implement the revisions made by the Sarbanes-Oxley Act to section 12(i) of the Exchange Act.[4] The interim rule provided that the Board will administer and enforce the sections of the Sarbanes-Oxley Act incorporated into section 12(i) of the Exchange Act with respect to registered banks. Consistent with the existing provisions of Regulation H, the interim rule also required registered banks to comply with any rules, regulations and forms issued by the SEC under the sections of the Sarbanes-Oxley Act incorporated into section 12(i) of the Exchange Act.

Explanation of Final Rule

The Board received two comments on the interim rule, both of which were filed by trade associations representing banking organizations. After carefully considering these comments, which are discussed below, the Board has adopted a final rule that is identical to the interim rule.

As required by section 12(i) of the Exchange Act, the final rule provides that the Board will administer and enforce the sections of the Sarbanes-Oxley Act described in Table 1 with respect to registered banks. The final rule also generally requires registered banks to comply with any rules, regulations and forms adopted by the SEC to implement the sections of the Sarbanes-Oxley Act listed in Table 1 (''New SEC Rules''), unless such rules, regulations or forms are modified by the Board. If the New SEC Rules require the filing of any documents with the SEC, registered banks must file such documents with the Board (rather than the SEC) in accordance with section 208.36 of Regulation H.

TABLE 1

Section of Sarbanes-Oxley Act	Description	Implementing SEC rules
Section 301 as (codified section 10A(m) of Exchange Act, 15 U.S.C. 78f(m)).	Establishes certain oversight, independence, funding and other requirements for the audit committees of public companies listed on a the national securities exchange, and requires the SEC to issue prohibit any national securities exchange or national securities association from listing the securities of an issuer that fails to comply with these audit committee requirements.	Proposed rules issued for comment. *See* 68 rules that FR 2638, Jan. 17, 2003. The SEC must adopt final rules by April 26, 2003.
Section 302	Mandates that the SEC adopt rules that require the principal executive officer(s) and principal financial officer(s) of public companies to include certain certifications in the issuer's annual and quarterly reports filed under the Exchange Act.	Final rules became effective August 29, 2002. *See* 67 FR 57275, Sep. 9, 2002.[5]
Section 303	Requires the SEC to issue rules prohibiting the officers and directors of public companies, and persons acting under their direction, from fraudulently influencing, coercing, manipulating, or misleading the issuer's independent auditor for purposes of rendering the issuer's financial statements materially misleading.	Proposed rules issued for comment. *See* 67 FR 65325, Oct. 24, 2002. The SEC must issue final rules by April 26, 2003.
Section 304	Requires the chief executive officer and chief financial officer of public companies to reimburse the issuer for certain compensation and profits received if the issuer is required to restate its financial reports due to material noncompliance, as a result of misconduct, with the Federal securities laws.	Section 304 became effective on July 30, 2002. No implementing rules are required.
Section 306(a)	Prohibits the directors and executive officers of any public company of equity securities from purchasing, selling or transferring any equity security acquired by the director or executive officer during any ''blackout period'' with respect to the security.	The SEC adopted final rules on January 8, 2003. *See* SEC Press Release 2003–6 Proposed rules were issued for comment in November 2002. *See* 67 FR 69249, Nov. 15, 2002.

[1] As of December 10, 2002, seventeen state member banks had a class of securities registered under section 12(b) or 12(g) of the Exchange Act and, thus, are considered registered banks.

[2] Pub. L. 102–204, 116 Stat. 745 (2002).

[3] *See* Sarbanes-Oxley Act at section 3(b)(4) (amending 15 U.S.C. 78*l*(i)).

[4] *See* 67 FR 57938, Sept. 13, 2002.

TABLE 1—Continued

Section of Sarbanes-Oxley Act	Description	Implementing SEC rules
Section 401(b)	Requires the SEC to issues rules that prohibit issuers from including misleading pro forma financial information in their filings with the SEC or in any public release, and that require issuers to reconcile any pro forma financial information included in such filings or public releases with the issuer's financial statements prepared in accordance with generally accepted accounting principles (GAAP).	The SEC adopted final rules on January 8, 2003. *See* SEC Press Release 2003–6. Proposed rules were issued for public comment in November 2002. *See* 67 FR 68790, Nov. 13, 2002.
Section 404	Mandates that the SEC issue rules that require all annual reports filed under section 13(a) or 15(d) of the Exchange Act to include certain statements and assessments related to the issuer's internal control structures and procedures for financial reporting. [6]	Proposed rules issued for comment. *See* 67 FR 66207, Oct. 30, 2002.
Section 406	Mandates that the SEC adopt rules that require public companies to (1) disclose in their periodic reports filed under the Exchange Act whether the issuer has adopted a code of ethics for its senior financial officers and, if not, the reasons why such a code has not been adopted; and (2) promptly disclose on Form 8–K any change to, or waiver of, the issuer's code of ethics.	The SEC adopted final rules on January 8, 2003. *See* SEC Press Release 2003–6. Proposed rules were issued for comment in October 2002. *See* 67 FR 66207, Oct. 30, 2002.
Section 407	Mandates that the SEC adopt rules that require public companies to disclose in their periodic reports filed under the Exchange Act whether the audit committee of the issuer includes at least one ''financial expert'' and, if not, the reasons why the audit committee does not include such an expert.	The SEC adopted final rules on January 8, 2003. *See* SEC Press Release 2003–6. Proposed rules were issued for comment in October 2002. *See* 67 FR 66207, Oct. 30, 2002.

[5] The SEC has proposed to modify these certification requirements in certain respects. *See* 67 FR 66207, Oct. 30, 2002.

[6] Section 404 also requires the registered public accounting firm that prepares or issues the audit report for the issuer's annual report to attest to, and report on, the issuer's assessment of its internal control structures and procedures for financial reporting.

Section 12(i) of the Exchange Act permits the Board to modify how the New SEC Rules apply to registered banks if the Board determines that the New SEC Rules are not necessary or appropriate in the public interest or for the protection of investors, and the Board publishes such findings (and the reasons supporting such findings) in the **Federal Register**.[7] The interim rule requested comment on whether it would be appropriate for the Board to modify any of the New SEC Rules at this time.

Commenters did not request that the Board specifically modify any of the New SEC Rules. One commenter, however, requested that the Board, in conjunction with the other Federal banking agencies, solicit public comment after any New SEC Rules are adopted for purposes of determining whether the rule should be modified for registered banks. The Board has reviewed and will continue to review the rules, regulations and forms adopted by the SEC under the Sarbanes-Oxley Act to determine whether it would be appropriate to modify these rules, regulations or forms for registered banks. Members of the public that believe any New SEC Rules issued in the future should be modified for registered banks are encouraged to contact their local Federal Reserve Bank or Board staff. If the Board determines that it would be appropriate to modify any New SEC Rule for registered banks, the Board will publish notice of the modification in the **Federal Register** in accordance with section 12(i) of the Exchange Act.[8]

Both commenters asked the Board to clarify how section 906 of the Sarbanes-Oxley Act applies to registered banks. Section 906 is a criminal provision that requires each ''periodic report filed by an issuer with the Securities [and] Exchange Commission pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934'' to be accompanied by a written statement by the issuer's chief executive officer and chief financial officer (or equivalent) that the report (1) fully complies with the requirements of section 13(a) or 15(d) of the Exchange Act, and (2) fairly presents, in all material respects, the financial condition and results of operations of the issuer.[9] This certification requirement is separate from the certification requirement imposed by section 302 of the Sarbanes-Oxley Act. Because section 906 amends the Federal criminal code, the Department of Justice (DOJ) is the appropriate agency to interpret its scope and application. Nevertheless, pending interpretive guidance from DOJ concerning section 906, the Board has indicated that any periodic reports (*i.e.* 10-K or 10-Q reports) filed with the Board by registered banks after July 29, 2002 (the effective date of section 906), should be accompanied by the certifications required by section 906.[10] This approach is consistent with the current practice of the Federal Deposit Insurance Corporation and Office of the Comptroller of the Currency with respect to state nonmember banks and national banks, respectively, that file reports with such agencies under section 12(i) of the Exchange Act.[11]

Other Sarbanes-Oxley Act Issues Relevant to Registered Banks

Besides the provisions discussed above, the Sarbanes-Oxley Act also

[7] *See* 15 U.S.C. 78l(i)(4).

[8] One commenter expressed concern that the audit committee and internal control report rules issued by the SEC under sections 301, 404 and 407 of the Sarbanes-Oxley Act may conflict with the audit committee and internal control report requirements imposed by section 36 of the Federal Deposit Insurance Act on insured depository institutions. *See* 12 U.S.C. 1831m; 12 CFR part 363. The SEC has indicated that it intends to work with the Federal banking agencies to eliminate, to the extent possible, conflicts between the internal controls reports required by section 404 of the Sarbanes-Oxley Act and the internal controls reports required by section 36 of the FDI Act. *See* 67 FR 66208, 66222, Oct. 30, 2002. Staffs of the Board and SEC also have met to discuss potential conflicts and overlaps between the Sarbanes-Oxley Act and Federal banking laws and regulations.

[9] Sarbanes-Oxley Act at section 906 (codified at 18 U.S.C. 1350).

[10] *See* Letter from Gerald A. Edwards, Jr., Associate Director and Chief Accountant-Supervision of the Board, to Chief Executive Officers and Chief Financial Officers of Banks Reporting to the Board under the Exchange Act, dated Aug. 15, 2002.

[11] *See* Letter from Robert F. Storch, Chief, Accounting and Securities Section of the FDIC, to Chief Executive Officers and Chief Financial Officers of Banks Reporting to the FDIC under the Exchange Act, dated Aug. 13, 2002.

includes a variety of other provisions that will affect all public companies, including state member banks that report to the Board under the Exchange Act. For example, the Act includes important changes relating to the independence of the external auditors of public companies. In addition, the Sarbanes-Oxley Act added several new disclosure requirements to sections 13 and 16 of the Exchange Act that apply to public companies that the Board will be responsible for administering and enforcing with respect to registered banks.[12]

Public banking organizations are encouraged to review the Sarbanes-Oxley Act and any implementing rules issued by the SEC. The Board also recently issued supervisory guidance designed to assist registered banks and other public banking organizations supervised by the Federal Reserve in understanding and complying with the requirements of the Sarbanes-Oxley Act.[13]

Regulatory Flexibility Act

Pursuant to section 4(a) of the Regulatory Flexibility Act (5 U.S.C. 604(a)), the Board must publish a final regulatory flexibility analysis with this rulemaking. The rule implements for registered banks several of the new reporting and disclosure obligations imposed by the Sarbanes-Oxley Act on public companies. Consistent with section 12(i) of the Exchange Act, the final rule requires registered banks to comply with any rules, regulations or forms that the SEC may issue under the relevant provisions of the Sarbanes-Oxley Act. By incorporating the SEC's rules, regulations and forms by reference, the rule seeks to minimize the potential conflict between the rule and the corresponding SEC rules and, thus, reduce the potential burden associated with complying with the Board's rule. Moreover, as noted above, the Board intends to monitor the SEC rules incorporated by reference into the Board's rule to determine whether it would be appropriate to modify these rules for registered banks.

The objectives and legal basis for the rule are discussed in the supplementary information set forth above. As of December 10, 2002, 17 state member banks had a class of securities registered under sections 12(b) or 12(g) of the Exchange Act and, thus, would be subject to the rule. As of September 30, 2002, only six of these institutions have assets of less than $100 million and are considered small entities for purposes of the Regulatory Flexibility Act. *See* 5 U.S.C. 601; 13 CFR 121.201.

Paperwork Reduction Act

In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3506; 5 CFR part 1320 Appendix A), the Board has reviewed the final rule under the authority delegated to the Board by the Office of Management and Budget. Consistent with the requirements of section 12(i) of the Exchange Act, the final rule requires registered banks to abide by any collection of information requirements adopted by the SEC under sections 301, 302, 303, 304, 306(a), 401(b), 404, 406 and 407 of the Sarbanes-Oxley Act of 2002, unless such collections are modified by the Board. As of December 10, 2002, there were 17 registered banks that will be subject to the final rule. Registered banks may request confidential treatment of any information submitted to the Board under the final rule in the manner described in section 208.36(d) of the Board's Regulation H (12 CFR 208.36(d)).

Because the SEC has not yet adopted final rules to implement many of the sections of the Sarbanes-Oxley Act referenced above, the Board is unable at this time to estimate the annual burden registered banks will incur in complying with the final rule. The Board notes that the SEC must consider the paperwork burden imposed by its rules in connection with its rulemaking process, and provide an estimate of the number of hours persons subject to the rule would spend each year in complying with any collections of information imposed by the SEC's rule. Registered banks and other persons interested in the potential paperwork burden imposed by the Board's rule should monitor the SEC's rulemaking process under the Sarbanes-Oxley Act.

The Federal Reserve may not conduct or sponsor, and an organization is not required to respond to, an information collection unless the Board has displayed a currently valid OMB control number. The OMB control number for the information collections required by the final rule is 7100–0091. The Federal Reserve has a continuing interest in the public's opinion of our collections of information. At any time, comments regarding any aspect of the collections of information required by the final rule, including suggestions for reducing burden, may be sent to: Jennifer J. Johnson, Secretary, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue, NW., Washington, DC 20551; and to the Office of Management and Budget, Paperwork Reduction Project (7100–0091), Washington, DC 20503.

Plain Language

Section 722 of the Gramm-Leach-Bliley Act (12 U.S.C. 4809) requires the Board to use ''plain language'' in all rules published in the **Federal Register** after January 1, 2000. The Board believes that the final rule is presented in a simple and straightforward manner and is consistent with this ''plain language'' directive.

Effective Date of Rule

The final rule will become effective on April 1, 2003. Because some of the provisions of the Sarbanes-Oxley Act to be administered and enforced by the Board had previously become effective, the Board made the interim rule effective immediately on publication in the **Federal Register** (*i.e.* September 13, 2002). The Board requested comment on all aspects of the interim rule and has carefully considered those comments in adopting this final rule.

List of Subjects in 12 CFR Part 208

Accounting, Banks, banking, Reporting and recordkeeping requirements, Securities.

Authority and Issuance

For the reasons set forth in the preamble, the Board of Governors of the Federal Reserve System amends part 208 of chapter II of title 12 of the Code of Federal Regulations as follows:

PART 208—MEMBERSHIP OF STATE BANKING INSTITUTIONS IN THE FEDERAL RESERVE SYSTEM (REGULATION H)

1. The authority citation for part 208 continues to read as follows:

Authority: 12 U.S.C. 24, 24a, 36, 92a, 93a, 248(a), 248(c), 321–338a, 371d, 461, 481–486, 601, 611, 1814, 1816, 1818, 1820(d)(9), 1823(j), 1828(o), 1831, 1831o, 1831p–1, 1831r–1, 1831w, 1831x, 1835a, 1843(l), 1882, 2901–2907, 3105, 3310, 3331–3351, and 3906–3909; 15 U.S.C. 78b, 78l(b), 78l(g),

[12] *See* Sarbanes-Oxley Act, sections 401(a), 402, 403 and 409 (to be codified at 15 U.S.C. 78m(i), (j), (k) and (l), and 78p(a)).

[13] *See* The Sarbanes-Oxley Act of 2002, SR Letter 02–20 (Oct. 29, 2002). One commenter expressed concern that the Board and the other Federal banking agencies may require all banking organizations to comply with some or all of the provisions that the Sarbanes-Oxley Act imposes only on public companies. As the Board previously has stated, the Board, in conjunction with the other Federal banking agencies, is reviewing its existing regulations and supervisory guidance to determine what, if any, changes may be appropriate in light of the Sarbanes-Oxley Act. Such review is outside the scope of this rulemaking. Nevertheless, the Board recognizes that nonpublic banking organizations typically have fewer resources and less complex operations than public banking organizations and that it may be inappropriate to require all nonpublic banking organizations to comply with requirements legislatively mandated only for public companies.

78l(i), 78o–4(c)(5), 78q, 78q–1, and 78w; 31 U.S.C. 5318; 42 U.S.C. 4012a, 4104a, 4104b, 4106, and 4128.

2. Section 208.36(a) is revised to read as follows:

§ 208.36 Reporting requirements for State member banks subject to the Securities Exchange Act of 1934.

(a) *Filing, disclosure and other requirements*—(1) *General.* Except as otherwise provided in this section, a member bank whose securities are subject to registration pursuant to section 12(b) or section 12(g) of the Securities Exchange Act of 1934 (the 1934 Act) (15 U.S.C. 78l(b) and (g)) shall comply with the rules, regulations and forms adopted by the Securities and Exchange Commission (Commission) pursuant to—

(i) Sections 10A(m), 12, 13, 14(a), 14(c), 14(d), 14(f) and 16 of the 1934 Act (15 U.S.C. 78f(m), 78l, 78m, 78n(a), (c), (d) and (f), and 78p); and

(ii) Sections 302, 303, 304, 306, 401(b), 404, 406 and 407 of the Sarbanes-Oxley Act of 2002 (codified at 15 U.S.C. 7241, 7242, 7243, 7244, 7261, 7262, 7264 and 7265).

(2) *References to the Commission.* Any references to the ''Securities and Exchange Commission'' or the ''Commission'' in the rules, regulations and forms described in paragraph (a)(1) of this section shall with respect to securities issued by member banks be deemed to refer to the Board unless the context otherwise requires.

* * * * *

By order of the Board of Governors of the Federal Reserve System, January 23, 2003.

Jennifer J. Johnson,

Secretary of the Board.

[FR Doc. 03–1922 Filed 1–27–03; 8:45 am]

BILLING CODE 6210–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2002–NM–318–AD; Amendment 39–13027; AD 2003–03–03]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 777 Series Airplanes Equipped With Rolls-Royce Model Trent 800 Series Engines

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule; request for comments.

SUMMARY: This amendment adopts a new airworthiness directive (AD) that is applicable to certain Boeing Model 777 series airplanes. This action requires revising the Airplane Flight Manual to specify that the engine anti–ice must be ''on'' during all ground and flight operations when icing conditions exist or are anticipated. This action is necessary to prevent ingestion of ice that could cause shutdown of both engines during operation in icing conditions, and result in a forced landing of the airplane.

DATES: Effective February 12, 2003.

Comments for inclusion in the Rules Docket must be received on or before March 31, 2003.

ADDRESSES: Submit comments in triplicate to the Federal Aviation Administration (FAA), Transport Airplane Directorate, ANM–114, Attention: Rules Docket No. 2002–NM–318–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056. Comments may be inspected at this location between 9 a.m. and 3 p.m., Monday through Friday, except Federal holidays. Comments may be submitted via fax to (425) 227–1232. Comments may also be sent via the Internet using the following address: *9-anm-iarcomment@faa.gov.* Comments sent via fax or the Internet must contain ''Docket No. 2002–NM–318–AD'' in the subject line and need not be submitted in triplicate. Comments sent via the Internet as attached electronic files must be formatted in Microsoft Word 97 for Windows or ASCII text.

The information pertaining to this AD may be examined at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington.

FOR FURTHER INFORMATION CONTACT: Margaret Langsted, Aerospace Engineer, Propulsion Branch, ANM–140S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–1335; fax (425) 227–1181.

SUPPLEMENTARY INFORMATION: The FAA has received a report of an engine surge and automatic shutdown on a Boeing Model 777 series airplane equipped with Rolls-Royce Trent 800 series engines, while in light icing conditions during descent. Investigation revealed that the airplane total air temperature (TAT) and the engine T2 probes were iced over. In addition, both engines were operating at minimum flight idle and the engine anti-ice systems had not activated. Boeing Model 777 series airplanes have a primary in-flight icing detection system (PIIDS) that senses icing conditions and automatically activates the engine and wing anti-ice systems, if the flight deck anti-ice switch is in the AUTO position (normal procedure). Activation of the engine anti-ice system sends hot air to the engine inlet lip to keep it free of ice buildup; raises the minimum allowable engine speed from ''minimum flight idle'' to ''approach idle,'' which improves the engine operating characteristics; and turns on the engine igniters to facilitate relight if a flameout should occur. The investigation indicated that the PIIDS did not detect icing and activate the engine anti-ice system; the engine surge was the result of ice ingestion; and the engine did not automatically recover from the engine surge. Such ingestion of ice could cause shutdown of both engines during operation in icing conditions, and result in a forced landing of the airplane.

Explanation of the Requirements of the Rule

Since an unsafe condition has been identified that is likely to exist or develop on other airplanes of the same type design, this AD is being issued to prevent ingestion of ice that could cause shutdown of both engines during operation in icing conditions, and result in a forced landing of the airplane. This AD requires revision of the Limitations Section of the Airplane Flight Manual (AFM) to remove certain procedures and to add certain other procedures that specify that engine anti-ice must be ''on'' during all ground and flight operations when icing conditions exist or are anticipated, except when the outside air temperature (OAT) is below −40 degrees Centigrade.

Interim Action

This is considered to be interim action until final action is identified, at which time the FAA may consider further rulemaking.

Determination of Rule's Effective Date

Since a situation exists that requires the immediate adoption of this regulation, it is found that notice and opportunity for prior public comment hereon are impracticable, and that good cause exists for making this amendment effective in less than 30 days.

Comments Invited

Although this action is in the form of a final rule that involves requirements affecting flight safety and, thus, was not preceded by notice and an opportunity for public comment, comments are invited on this rule. Interested persons are invited to comment on this rule by submitting such written data, views, or arguments as they may desire. Communications shall identify the Rules Docket number and be submitted in triplicate to the address specified

under the caption **ADDRESSES.** All communications received on or before the closing date for comments will be considered, and this rule may be amended in light of the comments received. Factual information that supports the commenter's ideas and suggestions is extremely helpful in evaluating the effectiveness of the AD action and determining whether additional rulemaking action would be needed.

Submit comments using the following format:

- Organize comments issue-by-issue. For example, discuss a request to change the compliance time and a request to change the service bulletin reference as two separate issues.
- For each issue, state what specific change to the AD is being requested.
- Include justification (*e.g.*, reasons or data) for each request.

Comments are specifically invited on the overall regulatory, economic, environmental, and energy aspects of the rule that might suggest a need to modify the rule. All comments submitted will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested persons. A report that summarizes each FAA-public contact concerned with the substance of this AD will be filed in the Rules Docket.

Commenters wishing the FAA to acknowledge receipt of their comments submitted in response to this rule must submit a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket Number 2002–NM–318–AD.'' The postcard will be date stamped and returned to the commenter.

Regulatory Impact

The regulations adopted herein will not have a substantial direct effect 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, it is determined that this final rule does not have federalism implications under Executive Order 13132.

The FAA has determined that this regulation is an emergency regulation that must be issued immediately to correct an unsafe condition in aircraft, and that it is not a ''significant regulatory action'' under Executive Order 12866. It has been determined further that this action involves an emergency regulation under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979). If it is determined that this emergency regulation otherwise would be significant under DOT Regulatory Policies and Procedures, a final regulatory evaluation will be prepared and placed in the Rules Docket. A copy of it, if filed, may be obtained from the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

2003–03–03 Boeing: Amendment 39–13027. Docket 2002–NM–318–AD.

Applicability: Model 777–200 and –300 series airplanes, equipped with Rolls-Royce Model Trent 800 series engines; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent ingestion of ice that could cause shutdown of both engines during icing conditions, and result in a forced landing of the airplane; accomplish the following:

Airplane Flight Manual (AFM) Revision

(a) Within 14 days after the effective date of this AD, revise the Limitations Section of the AFM per the following actions specified in paragraphs (a)(1) and (a)(2) of this AD (this may be accomplished by inserting a copy of this AD into the AFM):

(1) Remove the following wording from the Limitations Section of the AFM: ''Engine anti-ice must be ON during all ground operations, and either ON or in AUTO during flight, when icing conditions exist or are anticipated, except when the temperature is below −40 degrees C OAT. The primary ice detection system (if operative) will automatically turn the engine anti-ice system on and off as required in response to ice detection signals (flight mode only). Do not use anti-ice if OAT or TAT exceeds 10 degrees C (50 degrees F).''

(2) Insert the following wording into the Limitations Section of the AFM: ''Engine anti-ice must be ON during all ground and flight operations when icing conditions exist or are anticipated, except when the temperature is below −40 degrees C OAT. Do not use anti-ice if OAT or TAT exceeds 10 degrees C (50 degrees F).''

Alternative Methods of Compliance

(b) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Seattle ACO.

Note: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Seattle ACO.

Special Flight Permits

(c) Special flight permits may be issued in accordance with §§ 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

Effective Date

(d) This amendment becomes effective on February 12, 2003.

Issued in Renton, Washington, on January 21, 2003.

Vi L. Lipski,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 03–1816 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2003–14243; Airspace Docket No. 03–ACE–3]

Revocation of Class E Airspace; Brookfield, MO

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Direct final rule; request for comments.

SUMMARY: This revokes Class E airspace at Brookfield, MO. All instrument approach procedures for the Brookfield, General John J. Pershing Memorial Airport, MO are cancelled effective January 23, 2003, in preparation for closure of the airport. Controlled airspace extending upward from 700 feet above ground level (AGL) will no longer be needed to contain aircraft executing instrument procedures. This Action revokes the Class E airspace for Brookfield, General John J. Pershing Memorial Airport, MO.

DATES: This direct final rule is effective on 0901 UTC, April 17, 2003. Comments for inclusion in the Rules Docket must be received on or before February 28, 2003.

ADDRESSES: Send comments on this proposal to the Docket Management System, U.S. Department of Transportation, Room Plaza 401, 400 Seventh Street, SW., Washington DC 20590–0001. You must identify the docket number FAA–2003–14243/ Airspace Docket No. 03–ACE–3, at the beginning of your comments. You may also submit comments on the Internet at *http://dms. dot.gov.* You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone 1–800–647–5527) is on the plaza level of the Department of Transportation NASSIF Building at the above address.

FOR FURTHER INFORMATION CONTACT: Brenda Mumper, Air Traffic Division, Airspace Branch, ACE–502A DOT Regional Headquarters Building, Federal Aviation Administration, 901 Locust, Kansas City, MO 64106; telephone: (816) 329–2524.

SUPPLEMENTARY INFORMATION: This amendment to 14 CFR 71 revokes Class E airspace area at Brookfield, MO. All instrument approach procedures for the Brookfield, General John J. Pershing Memorial Airport, MO are cancelled effective January 23, 2003, in preparation for closure of the airport. Controlled airspace extending upward from 700 feet above ground level (AGL) will no longer be needed to contain aircraft executing instrument procedures. The area will be removed from appropriate aeronautical charts. Class E airspace extending upward from 700 feet or more above the surface of the earth are published in paragraph 6005 of FAA Order 7400.9K, dated August 30, 2002, and effective September 16, 2002, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document will be subsequently deleted from the Order.

The Direct Final Rule Procedure

The FAA anticipates that this regulation will not result in adverse or negative comment and, therefore, is issuing it as a direct final rule. Previous actions of this nature have not been controversial and have not resulted in adverse comments or objections. Unless a written adverse or negative comment, or a written notice of intent to submit an adverse or negative comment, is received within the comment period, the regulation will become effective on the date specified above. After the close of the comment period, the FAA will publish a document in the **Federal Register** indicating that no adverse or negative comments were received and confirming the date on which the final rule will become effective. If the FAA does receive, within the comment period, an adverse or negative comment, or written notice of intent to submit such a comment, a document withdrawing the direct final rule will be published in the **Federal Register**, and a notice of proposed rulemaking may be published with a new comment period.

Comments Invited

Interested parties are invited to participate in this 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 both docket numbers and 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 Docket No. FAA–2003–14243/Airspace Docket No. 03–ACE–3''. The postcard will be date/time stamped and returned to the commenter.

Agency Findings

The regulations adopted herein will not have a substantial direct effect 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, it is determined that this final rule does not have federalism implications under Executive Order 13132.

The FAA has determined that this regulation is noncontroversial and unlikely to result in adverse or negative comments. For the reasons discussed in the preamble, I certify that this regulation (1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under Department of Transportation (DOT) Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) if promulgated, 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.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

Accordingly, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, CLASS B, CLASS C, CLASS D, AND CLASS E AIRSPACE AREAS; AIRWAYS; ROUTES; AND REPORTING POINTS

1. The authority citation for 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.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9K, dated August 30, 2002, and effective September 16, 2002, is amended as follows:

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

* * * * *

ACE MO E5 Brookfield, MO [Removed]

* * * * *

Issued in Kansas City, MO on January 13, 2003.

Paul J. Sheridan,

Acting Manager, Air Traffic Division, Central Region.

[FR Doc. 03–1876 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Coast Guard

33 CFR Part 147

[CGD08–01–043]

RIN 2115–AG31

Safety Zone; Outer Continental Shelf Facility in the Gulf of Mexico

AGENCY: Coast Guard, DOT.

ACTION: Final rule.

SUMMARY: The Coast Guard is establishing a safety zone around a petroleum and gas production facility in Green Canyon 205A on the Outer Continental Shelf in the Gulf of Mexico. The facility needs to be protected from vessels operating outside the normal shipping channels and fairways, and placing a safety zone around this facility significantly reduces the threat of

allisions, oil spills and releases of natural gas. This regulation prevents all vessels from entering or remaining in the specified area around the facility except for the following: an attending vessel; a vessel under 100 feet in length overall not engaged in towing; or a vessel authorized by the Eighth Coast Guard District Commander.

DATES: This final rule is effective February 27, 2003.

ADDRESSES: Comments and material received from the public, as well as documents indicated in this preamble as being available in the docket, are part of docket [CGD08–01–043] and are available for inspection or copying at Commander, Eighth Coast Guard District (m), Hale Boggs Federal Bldg., 501 Magazine Street, New Orleans, LA, between 8 a.m. and 3:30 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Lieutenant (LT) Karrie Trebbe, Project Manager for Eighth Coast Guard District Commander, Hale Boggs Federal Bldg., 501 Magazine Street, New Orleans, LA 70130, telephone (504) 589–6271.

SUPPLEMENTARY INFORMATION:

Regulatory History

On April 2, 2001, we published a notice of proposed rulemaking (NPRM) entitled ''Safety Zone; Outer Continental Shelf Facility in the Gulf of Mexico'' in the **Federal Register** (67 FR 15505). We received no comments on the proposed rule. No public hearing was requested, and none was held.

Background and Purpose

The Coast Guard is establishing a safety zone around Chevron Genesis Spar (Genesis), Green Canyon 205A (GC205A), a petroleum producing facility in the Gulf of Mexico. That facility is located at position 27°46′46.365″ N, 90°31′06.553″ W.

The safety zone established by this regulation is in the deepwater area of the Gulf of Mexico. For the purposes of this regulation the deepwater area is considered to include waters of 304.8 meters (1,000 feet) or greater in depth extending to the limits of the Exclusive Economic Zone (EEZ) contiguous to the territorial sea of the United States and up to a distance of 200 nautical miles from the baseline. Vessels navigating in the area of the safety zone consist of large commercial shipping vessels, fishing vessels, cruise ships, tugs with tows and the occasional recreational vessel. An extensive system of navigational fairways is within the deepwater area. Those fairways include the Gulf of Mexico East-West Fairway, the entrance and exit route of the Mississippi River, and the Houston-Galveston Safety Fairway. Significant amounts of vessel traffic occur in or near the various fairways in the deepwater area.

Chevron U.S.A. Production Company (Chevron) requested that the Coast Guard establish a safety zone in the Gulf of Mexico around the moored spar buoy, Genesis. That request was made due to the high level of shipping activity around the facility and the safety concerns for both the personnel on board the facility and the environment. Chevron indicated that the location, production level, and number of personnel on board the facility make it highly likely that any allision with the facility would result in a catastrophic event. The Genesis, which is located in open waters where no fixed structures previously existed and is manned with a crew of approximately 160 people, is a high production oil and gas drilling facility that produces approximately 55,000 barrels of oil per day and 95 million cubic feet of gas per day.

The Coast Guard reviewed Chevron's concerns and agrees that the risk of allision to the facility and potential for loss of life and damage to the environment resulting from such an accident warrants the establishment of this safety zone. The regulation will significantly reduce the threat of allisions, oil spills and natural gas releases and will increase the safety of life, property, and the environment in the Gulf of Mexico. This regulation is issued pursuant to 14 U.S.C. 85 and 43 U.S.C. 1333 as set out in the authority citation for 33 CFR part 147.

Discussion of Comments and Changes

We received no comments on the proposed rule. Therefore, we have made no substantive changes to the provisions of the proposed rule.

Regulatory Evaluation

This rule is not a ''significant regulatory action'' under section 3(f) of Executive Order 12866, Regulatory Planning and Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order. It is not significant under the regulatory policies and procedures of the Department of Transportation (44 FR 11040; February 26, 1979).

The Coast Guard expects the economic impact of this rule to be so minimal that a full Regulatory Evaluation under paragraph 10(e) of the regulatory policies and procedures of DOT is unnecessary. The impacts on routine navigation are expected to be minimal because the safety zone does not encompass any nearby safety fairways.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we considered whether this rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities. Few privately owned fishing vessels and recreational boats/yachts operate in the area of the Genesis because it is located far offshore, and alternate routes are available for those that do. Use of alternate routes may cause a minimal loss of time (estimated loss of four to ten minutes) to their destination depending on how fast the vessel is traveling. The Coast Guard expects the impact of this regulation on small entities to be minimal.

If you think that your business, organization, or governmental jurisdiction qualifies as a small entity and that this rule would have a significant economic impact on it, please submit a comment (see **ADDRESSES**) explaining why you think it qualifies and how and to what degree this rule would economically affect it.

Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we offered to assist small entities in understanding the rule so they could better evaluate its effects on them and participate in the rulemaking process.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247).

Collection of Information

This rule calls for no new collection of information under the Paperwork

Reduction Act of 1995 (44 U.S.C. 3501–3520).

Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. We have analyzed this rule under that Order and have determined that it does not have implications for federalism.

Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 or more in any one year. Though this rule will not result in such an expenditure we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This rule will not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian Tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

Energy Effects

We have analyzed this rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that order because it is not a ''significant regulatory action'' under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This rule has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action. Therefore, it does not require a Statement of Energy Effects under Executive Order 13211.

Environment

We have considered the environmental impact of this proposed rule and concluded that under figure 2–1, paragraph 34(g), of Commandant Instruction M16475.1D, this rule is categorically excluded from further environmental documentation because it is not expected to result in any significant environmental impact as described in the National Environmental Policy Act of 1969 (NEPA). A ''Categorical Exclusion Determination'' is available in the docket for inspection or copying where indicated under **ADDRESSES**.

List of Subjects in 33 CFR Part 147

Continental shelf, Marine safety, Navigation (water).

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 147 as follows:

PART 147—SAFETY ZONES

1. The authority citation for part 147 continues to read as follows:

Authority: 14 U.S.C. 85; 43 U.S.C. 1333; 49 CFR 1.46.

2. Add § 147.825 to read as follows:

§ 147.825 Chevron Genesis Spar safety zone.

(a) *Description.* The Chevron Genesis Spar, Green Canyon 205A (GC205A), is located at position 27°46′46.365″ N, 90°31′06.553″ W. The area within 500 meters (1640.4 feet) from each point on the structure's outer edge is a safety zone.

(b) *Regulation.* No vessel may enter or remain in this safety zone except the following:

(1) An attending vessel;

(2) A vessel under 100 feet in length overall not engaged in towing; or

(3) A vessel authorized by the Commander, Eighth Coast Guard District.

Dated: January 10, 2003.

Roy J. Casto,

Rear Admiral, U.S. Coast Guard, Commander, Eighth Coast Guard District.

[FR Doc. 03–1872 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF TRANSPORTATION

Coast Guard

33 CFR Part 147

[CGD08–01–025]

RIN 2115–AG22

Safety Zones for Outer Continental Shelf Facilities in the Gulf of Mexico

AGENCY: Coast Guard, DOT.

ACTION: Final rule.

SUMMARY: The Coast Guard is establishing safety zones around five petroleum and gas production facilities in the Outer Continental Shelf in the Gulf of Mexico. The facilities, which include four platforms and one moored spar buoy, need to be protected from vessels operating outside the normal shipping channels and fairways. Placing safety zones around these facilities will significantly reduce the threat of allisions, oil spills and releases of natural gas. The regulation prevents all vessels from entering or remaining in specified areas around the platforms except for the following: An attending vessel; a vessel under 100 feet in length overall not engaged in towing; or a vessel authorized by the Eighth Coast Guard District Commander.

DATES: This final rule is effective February 27, 2003.

ADDRESSES: Comments and material received from the public, as well as documents indicated in this preamble as being available in the docket, are part of docket [CGD08–01–025] and are available for inspection or copying at Commander, Eighth Coast Guard District (m), Hale Boggs Federal Bldg., 501 Magazine Street, New Orleans, Louisiana, between 8 a.m. and 3:30 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Lieutenant (LT) Karrie Trebbe, Project Manager for Eighth Coast Guard District Commander, Hale Boggs Federal Bldg., 501 Magazine Street, New Orleans, LA 70130, telephone (504) 589–6271.

SUPPLEMENTARY INFORMATION:

Regulatory History

On December 10, 2001, the Coast Guard published a notice of proposed rulemaking (NPRM) entitled ''Safety

Zones for Outer Continental Shelf Facilities in the Gulf of Mexico'' in the **Federal Register** (66 FR 63642). We received one letter, one fax and one phone call commenting on the proposed rule. No public hearing was requested, and none was held.

Background and Purpose

The Coast Guard is establishing safety zones around the following petroleum producing facilities in the Gulf of Mexico: ExxonMobil Hoover Floating OCS Facility, a moored spar buoy, Alaminos Canyon Block 25A (AC25A), located at position 26°56′33″ N, 94°41′19.55″ W; Sir Douglas Morpeth Tension Leg Platform (Morpeth TLP), Ewing Bank Block 921A (EW 921A), located at position 28°02′05.28″ N, 90°01′22.12″ W; Allegheny Tension Leg Platform (Allegheny TLP), Green Canyon Block 254A (GC 254A), located at position 27°41′29.65″ N, 90°16′31.93″ W; Brutus Tension Leg Platform (Brutus TLP), Green Canyon Block 158 (GC 158), located at position 27°47′42.86″ N, 90°38′51.15″ W; and Enchilada Platform, Garden Banks Block 128A (GB 128A), located at position 27°52′31.31″ N, 91°59′11.09″ W.

These five safety zones are in the deepwater area of the Gulf of Mexico. For the purposes of this regulation, the deepwater area is considered to be waters of 304.8 meters (1,000 feet) or greater depth extending to the limits of the Exclusive Economic Zone (EEZ) contiguous to the territorial sea of the United States and extending to a distance up to 200 nautical miles from the baseline from which the breadth of the sea is measured. Navigation in the area of the safety zones consists of large commercial shipping vessels, fishing vessels, cruise ships, tugs with tows and the occasional recreational vessel. The deepwater area also includes an extensive system of shipping safety fairways that crisscross the deepwater area of the Gulf of Mexico. The shipping safety fairways include the Gulf of Mexico East-West Fairway, the entrance/exit route of the Mississippi River, and the Houston-Galveston Safety Fairway as listed in 33 CFR part 166. Significant amounts of vessel traffic occur in or near the various shipping safety fairways in the deepwater area.

ExxonMobil Production Company, AGIP Petroleum Co., Inc. (formerly known as British Borneo USA, Inc), and Shell Exploration and Production requested that the Coast Guard establish safety zones in the Gulf of Mexico around the following: ExxonMobil Production Company moored spar buoy, the ExxonMobil Hoover Floating OCS Facility; AGIP Petroleum Co., Inc. platforms, the Morpeth TLP and the Allegheny TLP; and Shell platforms, the Brutus TLP and the Enchilada Platform.

The request for the safety zones was made due to the high level of shipping activity around the facilities and the safety concerns for both the personnel on board the facilities and the environment. ExxonMobil Production Company, AGIP Petroleum Co., Inc., and Shell Exploration and Production, indicated that the location, production level, and number of personnel on board the facilities make it highly likely that any allision with the facilities would result in a catastrophic event. The Enchilada Platform is located near the edge of a shipping safety fairway. The ExxonMobil Hoover Floating OCS Facility, Brutus TLP, Morpeth TLP and Allegheny TLP are located in open waters where no fixed structures previously existed. All are high production oil and gas drilling platforms producing from 20,000 to 108,000 barrels of oil per day, and are manned with crews ranging from approximately 18 to 160 people.

The Coast Guard reviewed the concerns raised by ExxonMobil Production Company, AGIP Petroleum Co., Inc., and Shell Exploration and Production and agrees that the risk of allision to the facilities and the potential for loss of life and damage to the environment resulting from such an accident warrant the establishment of these safety zones. This regulation would significantly reduce the threat of allisions, oil and natural gas spills, and increase the safety of life, property, and the environment in the Gulf of Mexico. This regulation is issued pursuant to 14 U.S.C. 85 as set out in the authority citation for all of 33 CFR part 147.

Discussion of Comments and Changes

We received one letter, one fax and one phone call commenting on the proposed rule. One comment received telephonically from AGIP Petroleum Co., Inc., indicated that at the time of their original request they were known as British Borneo USA, Inc., but are now known as AGIP Petroleum Co., Inc. Therefore, the name British Borneo USA, Inc., has been replaced throughout the final rule with AGIP Petroleum Co., Inc.

One comment received via fax supported the proposed rule. The comment received by letter notified the Coast Guard that the safety zones encompassed blocks adjacent to each of the facilities that are leased and if one or more of the impacted blocks became available due to relinquishment of a lease then information regarding the zones would be included in the ''Information to Lessees in the Final Notice of Sale to potential bidders.'' The proposed rule does not have any impact on lessees' vessels and operations in the impacted blocks.

None of the comments received affected the provisions of the proposed rule.

Regulatory Evaluation

This rule is not a ''significant regulatory action'' under section 3(f) of Executive Order 12866, Regulatory Planning and Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order. It is not significant under the regulatory policies and procedures of the Department of Transportation (44 FR 11040; February 26, 1979).

We expect the economic impact of this rule to be so minimal that a full Regulatory Evaluation under paragraph 10(e) of the regulatory policies and procedures of DOT is unnecessary. The impacts on routine navigation are expected to be minimal because the safety zones do not encompass any nearby safety fairways.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities. Since the offshore facilities are located far offshore, few privately owned fishing vessels and recreational boats/yachts may be operating in the area and alternate routes are available for these vessels. Deviation of their intended course may cause a minimal loss of time (estimated loss of four to ten minutes) to their destination depending on how fast the vessel is traveling. The Coast Guard expects the impact of this regulation on small entities to be minimal.

If you are a small business entity and are significantly affected by this regulation please contact LT Karrie Trebbe, Project Manager for Eighth Coast Guard District Commander, Hale Boggs Federal Bldg., 501 Magazine

Street, New Orleans LA 70130, telephone (504) 589–6271.

Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we offered to assist small entities in understanding the rule so they could better evaluate its effects on them and participate in the rulemaking processes.

Small businesses may send comments on the actions of Federal Employees who enforce, or otherwise determine compliance with Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247).

Collection of Information

This rule calls for no new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. We have analyzed this rule under that Order and have determined that it does not have implications for federalism.

Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 or more in any one year. Though this rule will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This rule will not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not concern an environmental risk to health or risk to safety that may disproportionately affect children.

Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

Energy Effects

We have analyzed this rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that order because it is not a ''significant regulatory action'' under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. It has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action. Therefore, it does not require a Statement of Energy Effects under Executive Order 13211.

Environment

We have considered the environmental impact of this proposed rule and concluded that under figure 2–1, paragraph 34(g), of Commandant Instruction M16475.1D, this rule is categorically excluded from further environmental documentation because this rule is not expected to result in any significant environmental impact as described in the National Environmental Policy Act of 1969 (NEPA). A ''Categorical Exclusion Determination'' is available in the docket for inspection or copying where indicated under **ADDRESSES.**

List of Subjects in 33 CFR Part 147

Continental shelf, Marine safety, Navigation (water).

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 147 as follows:

PART 147—SAFETY ZONES

1. The authority citation for part 147 continues to read as follows:

Authority: 14 U.S.C. 85; 43 U.S.C. 1333; 49 CFR 1.46.

2. Add §§ 147.815, 147.817, 147.819, 147.821 and 147.823 to read as follows:

§ 147.815 ExxonMobil Hoover Floating OCS Facility safety zone.

(a) *Description.* The ExxonMobil Hoover Floating OCS Facility, Alaminos Canyon Block 25A (AC25A), is located at position 26°56′33″ N, 94°41′19.55″ W. The area within 500 meters (1640.4 feet) from each point on the structure's outer edge is a safety zone.

(b) *Regulation.* No vessel may enter or remain in this safety zone except the following:

(1) An attending vessel;

(2) A vessel under 100 feet in length overall not engaged in towing; or

(3) A vessel authorized by the Commander, Eighth Coast Guard District

§ 147.817 Sir Douglas Morpeth Tension Leg Platform safety zone.

(a) *Description.* The Sir Douglas Morpeth Tension Leg Platform (Morpeth TLP), Ewing Bank Block 921A (EW 921A), is located at position 28°02′05.28″ N, 90°01′22.12″ W. The area within 500 meters (1640.4 feet) from each point on the structure's outer edge is a safety zone.

(b) *Regulation.* No vessel may enter or remain in this safety zone except the following:

(1) An attending vessel;

(2) A vessel under 100 feet in length overall not engaged in towing; or

(3) A vessel authorized by the Commander, Eighth Coast Guard District.

§ 147.819 Allegheny Tension Leg Platform safety zone.

(a) *Description.* The Allegheny Tension Leg Platform (Allegheny TLP), Green Canyon Block 254A (GC 254A), is located at position 27°41′29.65″ N, 90°16′31.93″ W. The area within 500 meters (1640.4 feet) from each point on the structure's outer edge is a safety zone.

(b) *Regulation.* No vessel may enter or remain in this safety zone except the following:

(1) An attending vessel;

(2) A vessel under 100 feet in length overall not engaged in towing; or

(3) A vessel authorized by the Commander, Eighth Coast Guard District.

§ 147.821 Brutus Tension Leg Platform safety zone.

(a) *Description.* The Brutus Tension Leg Platform (Brutus TLP), Green Canyon Block 158 (GC 158), is located at position 27°47′42.86″ N, 90°38′51.15″ W. The area within 500 meters (1640.4 feet) from each point on the structure's outer edge is a safety zone.

(b) *Regulation.* No vessel may enter or remain in this safety zone except the following:

(1) An attending vessel;

(2) A vessel under 100 feet in length overall not engaged in towing; or

(3) A vessel authorized by the Commander, Eighth Coast Guard District.

§ 147.823 Enchilada Platform safety zone

(a) *Description.* The Enchilada Platform, Garden Banks Block 128A (GB 128A), is located at position 27°52′31.31″ N, 91°59′11.09″ W. The area within 500 meters (1640.4 feet) from each point on the structure's outer edge, not to extend into the adjacent East-West Gulf of Mexico Fairway, is a safety zone.

(b) *Regulation.* No vessel may enter or remain in this safety zone except the following:

(1) An attending vessel;

(2) A vessel under 100 feet in length overall not engaged in towing; or

(3) A vessel authorized by the Commander, Eighth Coast Guard District.

Dated: January 10, 2003.

Roy J. Casto

Rear Admiral, U.S. Coast Guard, Commander, Eighth Coast Guard District.

[FR Doc. 03–1871 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–15–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[AL–058–1–200312a; FRL–7444–9]

Approval and Promulgation of State Plan for Designated Facilities and Pollutants: AL

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is approving the sections 111(d) /129 plan submitted by the Alabama Department of Environmental Management (ADEM) for the State of Alabama on February 21, 2002, for implementing and enforcing the Emissions Guidelines (EG) applicable to existing Commercial and Industrial Solid Waste Incineration (CISWI) Units that commenced construction on or before November 30, 1999.

DATES: This direct final rule is effective March 31, 2003 without further notice, unless EPA receives adverse comments by February 27, 2003. If adverse comments are received, EPA will publish a timely withdrawal of the direct final rule in the **Federal Register** and inform the public that the rule will not take effect.

ADDRESSES: All comments should be addressed to: Joydeb Majumder, EPA Region 4, Air Toxics and Management Branch, 61 Forsyth Street, SW, Atlanta, Georgia 30303–8960. Copies of documents relative to this action are available at the following addresses for inspection during normal business hours: Environmental Protection Agency, Region 4, Air Planning Branch, 61 Forsyth Street, SW, Atlanta, Georgia 30303–8960 and Alabama Department of Environmental Management, 400 Coliseum Boulevard, Montgomery, Alabama 36110–2059. Anyone interested in examining this document should make an appointment with the office at least 24 hours in advance.

FOR FURTHER INFORMATION CONTACT: Joydeb Majumder at (404) 562–9121 or Sean Lakeman at (404) 562–9043.

SUPPLEMENTARY INFORMATION:

I. Background

On December 1, 2000, pursuant to sections 111 and 129 of the Clean Air Act (Act), EPA promulgated new source performance standards (NSPS) applicable to new CISWIs and EG applicable to existing CISWIs. The NSPS and EG are codified at 40 CFR part 60, subparts CCCC and DDDD, respectively. Subparts CCCC and DDDD regulate the following: Particulate matter, opacity, sulfur dioxide, hydrogen chloride, oxides of nitrogen, carbon monoxide, lead, cadmium, mercury, and dioxins and dibenzofurans.

Section 129(b)(2) of the Act requires States to submit to EPA for approval State Plans that implement and enforce the EG. State Plans must be at least as protective as the EG, and+ become Federally enforceable upon approval by EPA. The procedures for adoption and submittal of State Plans are codified in 40 CFR part 60, subpart B. EPA originally promulgated the subpart B provisions on November 17, 1975. EPA amended subpart B on December 19, 1995, to allow the subparts developed under section 129 to include specifications that supersede the general provisions in subpart B regarding the schedule for submittal of State Plans, the stringency of the emission limitations, and the compliance schedules.

This action approves the State Plan submitted by ADEM for the State of Alabama to implement and enforce subpart DDDD, as it applies to existing CISWI units only.

II. Discussion

ADEM submitted to EPA on February 21, 2002, the following in their 111(d)/129 State Plan for implementing and enforcing the EG for existing CISWIs under their direct jurisdiction in the State of Alabama: Public Participation-Demonstration that the Public Had Adequate Notice and Opportunity to Submit Written Comments and Attend the Public Hearing; Legal Authority; Emission Limits and Standards; Compliance Schedule; Inventory of CISWI Plants / Units; CISWI Emissions Inventory; Source Surveillance, Compliance Assurance and Enforcement Procedures; Submittal of Progress Reports to EPA; and applicable State of Alabama statutes and rules of the ADEM.

The approval of the Alabama State Plan is based on finding that: (1) ADEM provided adequate public notice of public hearings for the EG for CISWIs, and (2) ADEM also demonstrated legal authority to adopt emission standards and compliance schedules; enforceable applicable laws, regulations, standards, and compliance schedules; the ability to seek injunctive relief; obtain information necessary to determine compliance; require record keeping; conduct inspections and tests; require the use of monitors; require emission reports of owners and operators; and make emission data publicly available.

ADEM cites the following references for the legal authority: The Alabama Environmental Management Act, section 22–22A–4(n), Code of Alabama 1975, as amended; The Alabama Air Pollution Control Act, section 22–28–11(13) Code of Alabama 1975, as amended; and The ADEM Administrative Code, Rule 335–3–3–.05. On the basis of these statutes and rules of the State of Alabama, the State Plan is approved as being at least as protective as the Federal requirements for existing CISWI units.

ADEM cites all emission standards and limitations applicable to existing CISWI units in Chapter 335–3–3–.05 of part C. These standards and limitations have been approved as being at least as protective as the Federal requirements contained in subpart DDDD for existing CISWI units.

ADEM submitted the compliance schedule for CISWIs under their

jurisdiction in the State of Alabama. This portion of the Plan has been reviewed and approved as being at least as protective as Federal requirements for existing CISWI units.

In Appendix B of the Plan, ADEM submitted an emissions inventory of all designated pollutants for CISWI units under their jurisdiction in the State of Alabama. This portion of the Plan has been reviewed and approved as meeting the Federal requirements for existing CISWI units.

ADEM includes its legal authority to require owners and operators of designated facilities to maintain records and report to their Agency the nature and amount of emissions and any other information that may be necessary to enable their Agency to judge the compliance status of the facilities in Appendix B of the State Plan. In Appendix C, ADEM also cites its legal authority to provide for periodic inspection and testing and provisions for making reports of CISWI emissions data, correlated with emission standards that apply, available to the general public. Appendix C of the State Plan outlines the authority to meet the requirements of monitoring, record keeping, reporting, and compliance assurance. This portion of the Plan has been reviewed and approved as being at least as protective as Federal requirements for existing CISWI units.

As stated in the Plan, ADEM will provide progress reports of plan implementation updates to the EPA on an annual basis. These progress reports will include the required items pursuant to 40 CFR part 60, subpart B. This portion of the plan has been reviewed and approved as meeting the Federal requirement for State Plan reporting.

III. Final Action

This action approves the State Plan submitted by ADEM for the State of Alabama to implement and enforce subpart DDDD, as it applies to existing CISWI units only. The EPA is publishing this rule without prior proposal because the Agency views this as a noncontroversial submittal and anticipates no adverse comments. However, in the proposed rules section of this **Federal Register** publication, EPA is publishing a separate document that will serve as the proposal to approve the State Implementation Plan (SIP) revision should adverse comments be filed. This rule will be effective March 31, 2003 without further notice unless the Agency receives adverse comments by February 27, 2003.

If the EPA receives such comments, then EPA will publish a document withdrawing the final rule and informing the public that the rule will not take effect. All public comments received will then be addressed in a subsequent final rule based on the proposed rule. The EPA will not institute a second comment period. Parties interested in commenting should do so at this time. If no such comments are received, the public is advised that this rule will be effective on March 31, 2003 and no further action will be taken on the proposed rule.

IV. Statutory and Executive Order Reviews

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a ''significant regulatory action'' and therefore is not subject to review by the Office of Management and Budget. For this reason, this action is also not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001). This action merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. Accordingly, the Administrator certifies that this rule will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). Because this rule approves pre-existing requirements under state law and does not impose any additional enforceable duty beyond that required by state law, it does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4).

This rule also does not have tribal implications because it will not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified by Executive Order 13175 (65 FR 67249, November 9, 2000). This action also does not have Federalism implications because it does 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, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999). This action merely approves a state rule implementing a Federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act. This rule also is not subject to Executive Order 13045 ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), because it is not economically significant.

In reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the Clean Air Act. In this context, in the absence of a prior existing requirement for the State to use voluntary consensus standards (VCS), EPA has no authority to disapprove a SIP submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a SIP submission, to use VCS in place of a SIP submission that otherwise satisfies the provisions of the Clean Air Act. Thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply. This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

The Congressional Review Act, 5 U.S.C. section 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. section 804(2).

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by March 31, 2003. 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 62

Environmental protection, Air pollution control, Municipal waste

combustion units, Nitrogen dioxide, Particulate matter, Sulfur oxides.

Dated: January 16, 2003.

A. Stanley Meiburg,

Acting Regional Administrator, Region 4.

Chapter I, title 40 of the Code of Federal Regulation is amended as follows:

PART 62—[AMENDED]

1. The authority citation for part 62 continues to read as follows:

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

Subpart B—Alabama

2. Subpart B is amended by adding an undesignated center heading and § 62.107 to read as follows:

Air Emissions From Commercial and Industrial Solid Waste Incineration (CISWI) Units—Section 111(d)/129 Plan

§ 62.107 Identification of sources.

The Plan applies to existing Commercial and Industrial Solid Waste Incineration Units that commenced construction on or before November 30, 1999.

[FR Doc. 03–1869 Filed 1–27–03; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATION COMMISSION

47 CFR Part 0

[DA 03–44]

Freedom of Information Act

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Federal Communications Commission is modifying a section of the Commission's rules that implements the Freedom of Information Act (FOIA) Fee Schedule. This modification pertains to the charge for recovery of the full, allowable direct costs of searching for and reviewing records requested under the FOIA and the Commission's rules, unless such fees are restricted or waived. The fees are being revised to correspond to modifications in the rate of pay approved by Congress.

DATES: Effective January 28, 2003.

FOR FURTHER INFORMATION CONTACT: Shoko B. Hair, Freedom of Information Act Officer, Office of Performance Evaluation and Records Management, Room 5–C406, Federal Communications Commission, 445 12th Street, SW., Washington, DC 20554, (202) 418–1379 or via Internet at *shair@fcc.gov.*

SUPPLEMENTARY INFORMATION: The Federal Communications Commission is modifying § 0.467(a) of the Commission's rules. This rule pertains to the charges for searching and reviewing records requested under the FOIA. The FOIA requires Federal agencies to establish a schedule of fees for the processing of requests for agency records in accordance with fee guidelines issued by the Office of Management and Budget (OMB). In 1987, OMB issued its Uniform Freedom of Information Act Fee Schedule and Guidelines. However, because the FOIA requires that each agency's fees be based upon its direct costs of providing FOIA services, OMB did not provide a unitary, government-wide schedule of fees. The Commission based its FOIA Fee Schedule on the grade level of the employee who processes the request. Thus, the Fee Schedule was computed at a Step 5 of each grade level based on the General Schedule effective January 1987 (including 20 percent for personnel benefits). The Commission's rules provide that the Fee Schedule will be modified periodically to correspond with modifications in the rate of pay approved by Congress. *See* 47 CFR 0.467(a)(1) note.

In an Order adopted on January 15, 2003, and released on January 21, 2003 (DA–03–44), the Managing Director revised the schedule of fees set forth in 47 CFR 0.467 for the recovery of the full, allowable direct costs of searching for and reviewing agency records requested pursuant to the FOIA and the Commission's rules, 47 CFR 0.460, 0.461. The revisions correspond to modifications in the rate of pay, which was approved by Congress.

These modifications to the Fee Schedule do not require notice and comment because they merely update the Fee Schedule to correspond to modifications in rates of pay, as required under the current rules.

Accordingly, pursuant to the authority contained in § 0.231(b) of the Commission's rules, 47 CFR 0.231 (b), *it is hereby ordered,* that, effective on January 28, 2003, the Fee Schedule contained in § 0.467 of the Commission's rules, 47 CFR 0.467, is amended, as described herein.

List of Subjects in 47 CFR Part 0

Freedom of information.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

Rule Changes

For the reasons discussed in the preamble, the Federal Communications Commission amends 47 CFR part 0 as follows:

PART 0—COMMISSION ORGANIZATION

1.The authority citation for part 0 continues to read as follows:

Authority: 47 U.S.C. 155, unless otherwise noted.

2. Section 0.467 is amended by revising the last sentence, the table and the note in paragraph (a)(1), and paragraph (a)(2) to read as follows:

§ 0.467 Search and review fees.

(a)(1) * * * The fee is based on the grade level of the employee(s) who conduct(s) the search or review, as specified in the following schedule:

Grade	Hourly fee
GS–1	11.05
GS–2	12.02
GS–3	13.56
GS–4	15.22
GS–5	17.03
GS–6	18.98
GS–7	21.10
GS–8	23.36
GS–9	25.80
GS–10	28.42
GS–11	31.22
GS–12	37.42
GS–13	44.50
GS–14	52.58
GS–15	61.85

Note: These fees will be modified periodically to correspond with modifications in the rate of pay approved by Congress.

(2) The fees in paragraph (a) (1) of this section were computed at Step 5 of each grade level based on the General Schedule effective January 2003 and include 20 percent for personnel benefits.

* * * * *

[FR Doc. 03–1849 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 54

[CC Docket 96–45; FCC 02–339]

The Federal-State Joint Board on Universal Service

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: In this document, the Commission grants relief to parties who have, after September 12, 2001, mailed

to the Commission requests for review of an action of the Universal Service Administrative Company (Administrator) pursuant to section 54 of the Commission rules. We're deeming certain request filed after September 12, 2001 with the Commission as timely and we grant others a 60 day opportunity to resubmit their pleadings. The Commission takes this action to ensure that these parties are not prejudiced by continuing disruptions in the mail service.

DATES: Effective February 27, 2003.

FOR FURTHER INFORMATION CONTACT: Sheryl Todd (202) 418–7400 TTY: (202) 418–0484.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Order in CC Docket No. 96–45 released on January 7, 2003. The full text of this document is available on the Commission's Web site Electronic Comment Filing System and for public inspection during regular business hours in the FCC Reference Center, Room CY–A257, 445 Twelfth Street, SW., Washington, DC 20554.

I. Introduction

1. In this Order, the Commission deems certain requests for review as timely filed with the Commission, and we grant other petitioners a 60-day opportunity to resubmit their pleadings electronically. Specifically, this relief is provided to parties who have, after September 12, 2001, mailed to the Commission requests for review of an action of the Universal Service Administrative Company (Administrator) pursuant to section 54 of our rules, or petitions for reconsideration or applications for review arising from such pleadings (hereinafter collectively referred to as ''requests for review''). The Commission takes this action to ensure that these parties are not prejudiced by continuing disruptions in the mail service.

2. On December 24, 2001, we released the *Interim Filing Procedures Order,* 67 FR 3620, January 25, 2002, in response to disruptions in mail service arising from the events of September 11, 2001. In the *Interim Filing Procedures Order,* we established that, in addition to the then-available methods of filing requests for review with the Commission, including mail or electronic submission through the Commission's Electronic Comment Filing System (ECFS), parties could also file by facsimile or electronic mail. We instructed that, if requests for review were filed by electronic mail, pleadings should be filed at the following e-mail address: *CCBSecretary@fcc.gov* and could be submitted in Adobe Portable Document Format (PDF), Word, WordPerfect, or any other widely used word processing format. We further instructed that, if filed by facsimile, pleadings should be faxed to 202–418–0187, and that the fax transmission should include a cover sheet listing contact name, phone number, and, if available, an e-mail address. We made these methods optional. Thus, parties could, if they wished, continue to file requests for review by mail, manual delivery, or overnight delivery.

3. The Commission further provided that, where a party had mailed a request for review to the Commission on or after September 12, 2001, and that request for review was timely as of the date of mailing, the party could resubmit its request for review electronically within 30 days of the effective date of the *Interim Filing Procedures Order,* and have the request for review treated as having been filed with the Commission on the date that it was originally mailed. We provided this refiling option so that parties who had submitted their requests for review prior to the issuance of the *Interim Filing Procedures Order* might take advantage of the new electronic filing methods to ensure that their requests for review were timely received despite delays with the mail.

4. Since the *Interim Filing Procedures Order* was published in the **Federal Register** on January 24, 2002, we have received many requests for review that were submitted via United States mail. These parties did not take advantage of the new electronic filing options or the existing option to file via ECFS.

5. Under Commission rules, documents are considered to be filed with the Commission only upon receipt. Upon receipt, the Office of the Secretary date-stamps the appeals as received. Based on our review of the FCC date-stamp of the appeals, many mailed requests for review arrived at the Commission more than 60 days from the issuance of the decision being appealed. Thus, even under our *Interim Filing Procedures Order,* these appeals would be considered untimely. When comparing the FCC date-stamp to the postmark date or the date of the pleading, however, it is evident that some of these mailed requests for review were substantially delayed in transit due to continuing disruptions in mail service to federal agencies.

6. In our *Interim Filing Procedures Order,* we granted certain relief based on our belief that the mail system would return to normal operation. We have reviewed appeals filed by mail that were received after the release of the *Interim Filing Procedures Order.* From that review, we determined that there continued to be significant delays for appeals filed by mail. Only recently have we found that we are receiving requests for review within a reasonable time of the applicants' postmark. As such, we believe it is appropriate to extend the relief we originally ordered. Therefore, because of the unprecedented mail delays caused by the September 11, 2001 attacks and the subsequent appearance of anthrax in the United States mail system, we now conclude that it is appropriate to grant relief to certain parties that continued to rely on the United States mail to file pleadings with the FCC. The filings made by these petitioners fall into two categories. The first category of filings include petitions that are actually dated and/or have a postmarked date on the envelope that indicates that the petitioners took reasonable steps to ensure that its application would be timely filed. The second category of filings include requests that are not dated and arrived at the FCC secretary's office without proof of postmark.

7. Petitioners in the first category are set forth in Attachment C. Based on the dates of the requests for review and/or the postmarked dates on the envelopes when compared with the FCC-date stamp, we find that these petitioners reasonably complied with the terms of the *Interim Filing Procedures Order.* We find that these petitioners mailed their requests for review in a timely fashion. But for the disruptions in the mail service, their pleadings would have arrived at the Commission within the 60-day appeal period. Accordingly, we deem these requests for review as timely filed pursuant to this Order. Therefore, we direct that these requests for review shall be reviewed on their merits.

8. The Commission has also received several requests for review that either were not dated or did not have a postmark date. During the disruptions in the mail service and the implementation of the ensuing security measures, these pleadings were separated from their envelopes before they arrived in the FCC's Office of the Secretary. Thus, we do not have proof of postmark for these pleadings. We shall afford these petitioners an opportunity to resubmit their requests for review with proof that their original submissions were timely filed. These requests for review may be resubmitted electronically or by facsimile within 60 days of the release date of this Order. All requests for review re-submitted pursuant to this paragraph shall be accompanied by a signed affidavit or a declaration pursuant to Commission rule § 1.16 stating the date on which the

pleading was originally sent for delivery to the Commission and by what means (*i.e.*, by U.S. mail, express courier, or hand delivery). For this purpose only, the new pleading will be considered filed as of the date on which the original pleading was sent for delivery. The provisions of this paragraph are applicable to the petitioners listed in Attachment D of this Order. To the extent that it is determined that other filings not listed herein merit relief, we delegate to the Bureau the authority to grant such relief in keeping with this Order.

9. In addition, although we will continue to allow parties to submit requests for review by mail, express courier, or hand delivery, we note that mail in-take and processing procedures may continue to result in delivery disruption and affect the timeliness of their filings with the Commission. The Commission's filing procedures are designed to receive documents through the ECFS system. We strongly encourage parties to make use of the ECFS filing option to ensure that their requests for review arrive at the Commission in a timely fashion. Our ECFS filing option ensures accurate and more efficient processing. Parties will still be able to file by facsimile at 202–418–0187.

List of Subjects in 47 CFR Part 54

Communications common carriers, Health facilities, Libraries, Reporting and recordkeeping requirement, Schools, Telecommunications and Telephone.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1747 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[DA 96–1004; MM Docket No. 94–125; RM–8534, RM–8575]

Radio Broadcasting Services; Castroville, Fredericksburg, and Helotes, TX

AGENCY: Federal Communications Commission.

ACTION: Correcting amendments.

SUMMARY: This document contains corrections to section 73.202(b), FM Table of Allotments under Texas for the communities of Fredericksburg and Helotes, which were published in the **Federal Register** of Monday, July 22, 1996, (61 FR 37840).

DATES: Effective January 28, 2003.

FOR FURTHER INFORMATION CONTACT: Robert Hayne, Media Bureau, (202) 418–2177.

SUPPLEMENTARY INFORMATION:

Background

The Commission's *Memorandum Opinion and Order,* MM Docket No. 94–125, adopted June 28, 1996, and released July 5, 1996, rescinded the *Report and Order* in this proceeding, *see* 60 FR 322298, published June 21, 1995. The *Memorandum Opinion and Order* granted the Petition for Reconsideration filed by October Communications Group, Inc directed to the *Report and Order* in this proceeding, by reallotting Channel 266C from Fredericksburg, Texas, to Helotes, Texas, and modified the license of Station KONO–FM, Channel 266C, Fredericksburg, Texas, to specify Helotes, Texas as the community of license. On October 30, 1998, Station KONO–FM was granted a license (BLH–19980731KB) to specify operation on Channel 266C1 in lieu of Channel 266C at Helotes, Texas.

Need for Correction

As published, the amendatory language was omitted from the summary.

List of Subjects in 47 CFR Part 73

Radio, Radio broadcasting.

Accordingly, 47 CFR part 73 is corrected by making the following correcting amendments:

PART 73—RADIO BROADCAST SERVICES

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

Authority: 47 U.S.C. 154, 303, 334 and 336.

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under Texas, is amended by removing Fredericksburg, Channel 266C and by adding Helotes, Channel 266C1.

Dated: January 23, 2003.

John A. Karousos,

Assistant Chief, Audio Division, Media Bureau.

[FR Doc. 03–1836 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Parts 571 and 590

[Docket No. NHTSA 2000–8572]

RIN 2127–AI33

Federal Motor Vehicle Safety Standards; Tire Pressure Monitoring Systems; Correction

AGENCY: National Highway Traffic Safety Administration, DOT.

ACTION: Correcting amendments.

SUMMARY: On June 5, 2002, the National Highway Traffic Safety Administration (NHTSA) published a final rule amending the standard on controls and displays, adding a new standard on tire pressure monitoring systems, and amending and re-titling a part on tire pressure monitoring system phase-in reporting requirements. The final rule included a phase-in schedule for compliance with the tire pressure monitoring system (TPMS) standard for manufacturers of passenger cars, trucks, multipurpose passenger vehicles, and buses with a gross vehicle weight rating of 10,000 pounds or less, except those vehicles with dual wheels on an axle. This document corrects NHTSA's inadvertent omission of a provision excluding final-stage manufacturers and alterers from compliance with the TPMS requirements of these standards until the end of the phase-in period (*i.e.*, November 1, 2006).

DATES: These amendments to the final rule are effective February 27, 2003.

FOR FURTHER INFORMATION CONTACT: The following persons at the NHTSA, 400 Seventh Street, SW., Washington, DC 20590.

For non-legal issues, you may call Mr. George Soodoo or Mr. Joseph Scott, Office of Crash Avoidance Standards (Telephone: 202–366–2720) (Fax: 202–366–4329).

For legal issues, you may call Mr. Eric Stas, Office of Chief Counsel (Telephone: 202–366–2992) (Fax: 202–366–3820).

SUPPLEMENTARY INFORMATION:

I. Background

Federal Motor Vehicle Safety Standard (FMVSS) No. 138, ''Tire Pressure Monitoring Systems,'' was developed in fulfillment of the congressional mandate contained in the Transportation Recall Enhancement, Accountability, and Documentation (TREAD) Act of 2000. The new standard requires installation of tire pressure

monitoring systems that warn the driver when a tire is significantly under-inflated. On June 5, 2002, NHTSA published the first part of a two-part final rule amending Standard No. 101, ''Controls and displays,'' adding a new Standard No. 138, ''Tire Pressure Monitoring Systems,'' and amending and re-titling Part 590, ''Tire Pressure Monitoring System Phase-In Reporting Requirements'' (67 FR 38704). That document established two compliance options for the short-term (*i.e.*, for the period between November 1, 2003, and October 31, 2006). The second part of the final rule will be issued by March 1, 2005, and will establish performance requirements for the long-term (*i.e.*, for the period beginning on November 1, 2006).

Both the notice of proposed rulemaking (NPRM) (66 FR 38982, July 26, 2001) and the first part of the final rule discussed a phase-in of compliance with the new TPMS requirements, although the NPRM did not propose any specific phase-in plan for discussion. The final rule requires a manufacturer to certify at least ten percent of its vehicles manufactured between November 1, 2003 and October 31, 2004 (inclusive) as compliant with the new TPMS requirements. The percentage of compliant vehicles is determined based on: (a) The manufacturer's average annual production of vehicles manufactured on or after November 1, 2000, and before November 1, 2003; or (b) the manufacturer's production on or after November 1, 2003, and before November 1, 2004. Based upon a similar calculation, for vehicles manufactured on or after November 1, 2004, and before November 1, 2005, the number of vehicles complying with the standard must not be less than thirty-five percent of production, and for vehicles manufactured on or after November 1, 2005, and before November 1, 2006, the figure must rise to not less than sixty-five percent of production. The phase-in period ends on November 1, 2006, at which time all vehicles covered by the standard must comply with the new requirements.

The final rule contains an exclusion of small volume manufacturers from the requirements of the standard during the phase-in period. We provided this exclusion pursuant to a public comment request by Vehicle Services Consulting, Inc. (VSC), a representative of small volume vehicle manufacturers.

No commenter requested that final-stage manufacturers of vehicles built in two or more stages be excluded from the phase-in. However, NHTSA has historically excluded final-stage manufacturers from the phase-in requirements of its various safety standards. Despite this practice, the agency inadvertently omitted such an exclusion from the TPMS final rule.

Since the publication of the June 2002 final rule, NHTSA has received thirteen petitions for reconsideration from: (1) Ferrari S.P.A.; (2) Delphi Auto Inc.; (3) Japan Automobile Tyre Manufacturers Association, Inc. (JATMA); (4) Johnson Controls, Inc.; (5) Volkswagen of America, Inc.; (6) Bureau de Normalisation de l'Automobile (BNA) ISO/TC22/WG12; (7) Porsche Cars North America, Inc.; (8)Alliance of Automobile Manufacturers (Alliance); (9) Rubber Manufacturers Association (RMA); (10) Aviation Upgrade Technologies; (11) Vehicle Services Consulting, Inc. (VSC); and (12) DENSO International America, Inc. (DENSO); and (13) Maserati S.P.A. NHTSA will respond to those petitions through a subsequent notice to be published in the **Federal Register**. However, it should be noted that none of the petitions stated any opposition to an exclusion from the phase-in for final-stage manufacturers.

Further, on October 2, 2002, the National Truck Equipment Association (NTEA) submitted a request for legal interpretation asking for guidance on whether final-stage manufacturers are required to provide tire pressure monitoring systems during the phase-in period under the new and amended regulations, even when the incomplete vehicle is not so equipped by the incomplete (chassis) manufacturer. If that were indeed the case, NTEA asked that its request be treated as a petition for rulemaking to exclude final-stage manufacturers and alterers from the TPMS phase-in.

II. Summary of the Corrections

Instead of granting NTEA's petition for rulemaking, NHTSA has decided to publish a correcting amendment because it inadvertently omitted from the final rule an exclusion for final-stage manufacturers and alterers from compliance with the TPMS standard until the final year of the phase-in. As discussed below, the phase-in of the TPMS requirements has the potential to create significant problems for many final-stage manufacturers and alterers. Again, while NHTSA did not discuss in the NPRM the specific requirements that would be associated with a phase-in, the agency has addressed that issue in several recent rulemakings that provided a similar exclusion for final-stage manufacturers.

The current situation impacting final-stage manufacturers is similar to the one that the agency encountered during the phase-in that extended the quasi-static side door strength requirements of FMVSS No. 214, ''Side Impact Protection,'' to trucks, buses, and multipurpose passenger vehicles with a gross vehicle weight rating of 10,000 pounds or less (LTVs) (57 FR 30917, July 13, 1992). Like other manufacturers, final-stage manufacturers must certify that their vehicles meet all applicable safety standards. However, final-stage manufacturers complete or modify vehicles supplied by incomplete vehicle manufacturers and often rely on the representations in those manufacturers' incomplete vehicle document (IVD) as a basis for certification. Final-stage manufacturers and alterers have no control over the year of the phase-in in which a particular vehicle model will be certified as complying with the new requirements. Typically, a major manufacturer will elect to meet the phase-in requirements by scheduling its changes so that some of its models are changed in each year of the phase-in, instead of changing all models in a single year. While this practice allows the manufacturers to meet the phase-in requirements with minimal disruption to their manufacturing processes, it may significantly complicate final-stage manufacturers' efforts to secure appropriate compliant vehicles to either complete or modify as part of their standard operations. Put simply, final-stage manufacturers may have difficulty meeting the phase-in schedule because they have no control over when particular incomplete vehicles will be brought into compliance with the performance requirements being phased-in.

The difficulties faced by final-stage manufacturers and alterers in meeting the TPMS phase-in requirements are no less compelling than the difficulties they faced in the context of other phase-ins. Accordingly, NHTSA is correcting the June 2002 final rule to exclude final-stage manufacturers from compliance with the FMVSS No. 138 until the end of the phase-in (*i.e.*, November 1, 2006). This is the same approach for phase-ins that the agency has followed in a number of other recent rulemakings, including: Standard No. 208's automatic crash protection requirements for LTVs (56 FR 12472, 12479–80, March 26, 1991) and its more recently published advanced air bag requirements (65 FR 30680, 30721, May 12, 2000); Standard No. 214's extension of quasi-static door strength requirements to trucks, buses, and multipurpose passenger vehicles (57 FR 30917, 30921, July 13, 1992); Standard No. 201's requirements for protection for when an occupant's head

strikes upper interior components (60 FR 43031, 43049, August 18, 1995); and Standard No. 225's requirements for new child restraint anchorage systems (64 FR 10786, 10811, March 5, 1999).

Given that the agency raised the issue of the phase-in in both the NPRM and the final rule and the general understanding that commenters had concerning how the agency implemented phase-ins in other rulemakings, NHTSA believes that establishment of an exclusion for final-stage manufacturers until the final year of the phase-in along the lines of the above-cited agency precedent is a corrective action within the scope of the final rule. This correcting amendment relieves final-stage manufacturers and alterers from the requirement to assure that a specified percentage of their vehicles comply with the TPMS requirements of Standard No. 101 and Standard No. 138 during the phase-in period. However, once the phase-in is completed, all subject vehicles, including those produced by final-stage manufacturers and alterers, must be equipped with tire pressure monitoring systems.

This correction also amends 49 CFR 590.3 ''Applicability'' (Tire Pressure Monitoring System Phase-In Reporting Requirements) to exclude final-stage manufacturers and small volume manufacturers from phase-in reporting requirements because they are not subject to the phase-in.

These amendments to the final rule are effective 30 days after the date of publication in the **Federal Register**. These amendments correct the omission of a provision from the final rule that was published on June 5, 2002. Remedying this oversight on the part of the agency will not impose any additional substantive requirements or burdens on manufacturers. Therefore, NHTSA finds for good cause that any notice of proposed rulemaking and opportunity for comment on these amendments are not necessary.

III. Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866, ''Regulatory Planning and Review'' (58 FR 51735, October 4, 1993), provides for making determinations whether a regulatory action is ''significant'' and, therefore, subject to Office of Management and Budget (OMB) review and to 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:

(1) Have an annual effect on the economy of $100 million or more or adversely affects 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;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

We considered the impact of the June 5, 2002 final rule under Executive Order 12866 and the Department of Transportation's regulatory policies and procedures. That rule was determined to be a significant regulatory action under section 3(f) of the Executive Order because compliance with the rule was expected to have on annual effect on the economy of over $100 million. Consequently, the rule was reviewed by the Office of Management and Budget under Executive Order 12866. The rule was also determined to be significant within the meaning of the Department of Transportation's Regulatory Policies and Procedures (44 FR 11034, February 26, 1979).

Today's notice providing a correcting amendment is not a significant regulatory action within the meaning of Executive Order 12866, because the amendment does not impose any new requirements on manufacturers. It simply clarifies implementation of the phase-in by correcting the inadvertent omission of a provision to exclude final-stage manufacturers and alterers from compliance with the TPMS requirements of Federal Motor Vehicle Safety Standards No. 101 and No. 138 until the end of the phase-in period (*i.e.* November 1, 2006).

Executive Order 13132

Executive Order 13132, ''Federalism'' (64 FR 43255, August 10, 1999), requires NHTSA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that 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.'' Under Executive Order 13132, the agency may not issue a regulation with Federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, the agency consults with State and local governments, or the agency consults with State and local officials early in the process of developing the proposed regulation. NHTSA also may not issue a regulation with Federalism implications and that preempts a State law unless the agency consults with State and local officials early in the process of developing the proposed regulation.

The June 5, 2002 final rule was analyzed in accordance with the principles and criteria set forth in Executive Order 13132, and the agency determined that the rule would not have sufficient federalism implications to warrant consultations with State and local officials or the preparation of a federalism summary impact statement. Today's notice will not have any additional economic impact on any of the entities covered under Executive Order 13132.

Executive Order 13045

Executive Order 13045, ''Protection of Children from Environmental Health and Safety Risks'' (62 FR 19855, April 23, 1997), applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental, health or safety risk that NHTSA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the agency.

The June 5, 2002 final rule establishing requirements for incorporation of tire pressure monitoring systems in new vehicles was economically significant as defined in Executive Order 12866. However, it did not involve decisions based on health and safety risks that disproportionately affect children. Today's amendment does not make any changes to the final rule that would disproportionately affect children.

Executive Order 12988

Pursuant to Executive Order 12988, ''Civil Justice Reform'' (61 FR 4729,

February 7, 1996), the agency has considered whether this amendment will have any retroactive effect. This correcting amendment does not have any retroactive effect. Under 49 U.S.C. 30103, whenever a Federal motor vehicle safety standard is in effect, a State may not adopt or maintain a safety standard applicable to the same aspect of performance which is not identical to the Federal standard, except to the extent that the state requirement imposes a higher level of performance and applies only to vehicles procured for the State's use. 49 U.S.C. 30161 sets forth a procedure for judicial review of final rules establishing, amending, or revoking Federal motor vehicle safety standards. That section does not require submission of a petition for reconsideration or other administrative proceedings before parties may file suit in court.

Regulatory Flexibility Act

Pursuant to the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996), whenever an agency is required to publish a notice of rulemaking for any proposed or final rule, it must prepare and make available for public comment a regulatory flexibility analysis that describes the effect of the rule on small entities (*i.e.*, small businesses, small organizations, and small governmental jurisdictions). However, no regulatory or flexibility analysis is required if the head of an agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. SBREFA amended the Regulatory Flexibility Act to require Federal agencies to provide a statement of the factual basis for certifying that a rule will not have a significant economic impact on a substantial number of small entities.

In the June 5, 2002 **Federal Register** final rule, NHTSA certified that that final rule will not have a significant economic impact on a substantial number of small entities. I have considered the effects of today's amendment under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) and certify that this amendment would not have a significant economic impact on a substantial number of small entities. The amendments made in this document would not impose any additional costs on small entities. The Regulatory Flexibility Act does not, therefore, require a regulatory flexibility analysis.

National Environmental Policy Act

NHTSA has analyzed this amendment for the purposes of the National Environmental Policy Act, and the agency has determined that it will not have any significant impact on the quality of the human environment.

Paperwork Reduction Act

Under the Paperwork Reduction Act of 1995, a person is not required to respond to a collection of information by a Federal agency unless the collection displays a valid OMB control number. This correcting amendment does not establish any new information collection requirements.

National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, section 12(d) (15 U.S.C. 272) directs the agency to use voluntary consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or is otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies, such as the Society of Automotive Engineers (SAE). The NTTAA directs us to provide Congress (through OMB) with explanations when the agency decides not to use available and applicable voluntary consensus standards. The NTTAA does not apply to symbols.

Today's amendment to provide an exclusion for final-stage manufacturers from the TPMS rule's requirements until the final year of the phase-in does not involve any issues related to standards, and in fact, there are no voluntary consensus standards related to TPMS that are available at this time.

Unfunded Mandates Reform Act

Section 202 of the Unfunded Mandates Reform Act of 1995 (UMRA) requires Federal agencies to prepare a written assessment of the costs, benefits, and other effects of proposed or final rules that include a Federal mandate likely to result in the expenditure by State, local, or tribal governments, in the aggregate, or by the private sector, of more than $100 million in any one year (adjusted for inflation with base year of 1995). Before promulgating a NHTSA rule for which a written statement is needed, section 205 of the UMRA generally requires the agency to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows the agency to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the agency publishes with the final rule an explanation why that alternative was not adopted.

The June 5, 2002 final rule will result in an expenditure of more that $100 million by vehicle manufacturers and/or their suppliers, and, as discussed in the final rule, the agency chose two compliance options that will provide manufacturers with broad flexibility to minimize their costs of compliance with the TPMS Standard during the phase-in period. Today's correcting amendment does not impose any unfunded mandates under the Unfunded Mandates Reform Act of 1995, because it would not impose any costs or requirements. Thus, this amendment is not subject to the requirements of sections 202 and 205 of the UMRA.

Regulation Identification Number (RIN)

The Department of Transportation assigns a regulation identification number (RIN) to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. You may use the RIN contained in the heading at the beginning of this document to find this action in the Unified Agenda.

List of Subjects in 49 CFR Parts 571 and 590

Imports, Motor vehicle safety, Reporting and recordkeeping requirements, Tires.

Accordingly, 49 CFR Parts 571 and 590 are corrected by making the following correcting amendments:

PART 571—FEDERAL MOTOR VEHICLE SAFETY STANDARDS

1. The authority citation for Part 571 of Title 49 continues to read as follows:

Authority: 49 U.S.C. 322, 30111, 30115, 30117, and 30166; delegation of authority at 49 CFR 1.50.

2. Section 571.138 is amended by adding S7.7 to read as follows:

§ 571.138 Standard No. 138; Tire pressure monitoring systems.

* * * * *

S7.7. Final-stage manufacturers and alterers.

Vehicles that are manufactured in two or more stages or that are altered (within the meaning of 49 CFR § 567.7) after having previously been certified in accordance with Part 567 of this chapter are not subject to the requirements of S7.1 through S7.5.

* * * * *

PART 590—TIRE PRESSURE MONITORING SYSTEM PHASE-IN REPORTING REQUIREMENTS

3. The authority citation for Part 590 of Title 49 continues to read as follows:

Authority: 49 U.S.C. 322, 30111, 30115, 30117, and 30166; delegation of authority at 49 CFR 1.50.

4. Section 590.3 is revised to read as follows:

§ 590.3 Applicability.

(a) Except as provided in paragraph (b) of this section, this part applies to manufacturers of passenger cars, multipurpose passenger vehicles, trucks, and buses with a gross vehicle weight rating of 4,536 kilograms (10,000 pounds) or less, except those vehicles with dual wheels on an axle.

(b) The reporting requirements of this part do not apply to small volume manufacturers, which are excluded from the compliance during the phase-in period under S7.6 of Standard No. 138 (49 CFR 571.138), or to final-stage manufacturers and alterers, which are excluded from compliance during the phase-in period under S7.7 of Standard No. 138 (49 CFR 571.138).

Issued: January 3, 2003.

Noble Bowie,

Director, Office of Planning and Consumer Standards.

[FR Doc. 03–1321 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Part 579

[Docket No. NHTSA 2001–10773; Notice 4]

RIN 2127–AJ04

Reporting of Information and Documents About Foreign Safety Recalls and Campaigns Related to Potential Defects

AGENCY: National Highway Traffic Safety Administration (NHTSA), DOT.

ACTION: Final rule.

SUMMARY: This document responds to a petition for reconsideration of the final rule published on October 11, 2002, that implemented the foreign safety recall and safety campaign reporting provisions of the Transportation Recall Enhancement, Accountability, and Documentation (TREAD) Act. In response to the petition, we are correcting two provisions to correspond with statements made in the preamble to the final rule. We are also amending the date on which the first annual list of substantially similar vehicles must be submitted, and specifying how reports may be submitted electronically.

DATES: Effective Date: The effective date of this final rule is February 27, 2003.

FOR FURTHER INFORMATION CONTACT: For non-legal issues, contact Jonathan White, Office of Defects Investigation, NHTSA (phone: 202–366–5226). For legal issues, contact Taylor Vinson, Office of Chief Counsel, NHTSA (phone: 202–366–5263).

SUPPLEMENTARY INFORMATION:

I. Background

On October 11, 2002, NHTSA published a final rule implementing the foreign safety recall and safety campaign reporting provisions of the Transportation Recall Enhancement, Accountability, and Documentation (TREAD) Act, established by 49 U.S.C. 30166(l) (67 FR 63295). *See* 49 CFR part 579, particularly subpart B. The reader is referred to that document, and the prior Notice of Proposed Rulemaking (NPRM) (66 FR 51907, October 11, 2001) for further information.

A timely petition for reconsideration of the rule was filed by the Alliance of Automobile Manufacturers (the ''Alliance'').

To address foreign defect reporting and other issues, the TREAD Act (Pub. L. 106–414) was enacted on November 1, 2000. Section 3(a) of the TREAD Act amended 49 U.S.C. 30166 to add a new subsection (l), which reads as follows:

(l) Reporting of Defects in Motor Vehicles and Products in Foreign Countries—

(1) Reporting of Defects, Manufacturer Determination.—Not later than 5 working days after determining to conduct a safety recall or *other safety campaign* in a foreign country on a motor vehicle or motor vehicle equipment that is identical or substantially similar to a motor vehicle or motor vehicle equipment offered for sale in the United States, the manufacturer shall report the determination to the Secretary.

(2) Reporting of Defects, Foreign Government Determination.—Not later than 5 working days after receiving notification that the government of a foreign country has determined that a safety recall or *other safety campaign* must be conducted in the foreign country on a motor vehicle or motor vehicle equipment that is identical or substantially similar to a motor vehicle or motor vehicle equipment offered for sale in the United States, the manufacturer shall report the determination to the Secretary.

(3) Reporting Requirements.—The Secretary shall prescribe the contents of the notification required by this subsection.

(emphasis supplied)

The final rule adopted the following definition of ''other safety campaign:'

Other safety campaign means an action in which a manufacturer communicates with owners and/or dealers in a foreign country with respect to conditions under which motor vehicles or equipment should be operated, repaired, or replaced that relate to safety (excluding promotional and marketing materials, customer satisfaction surveys, and operating instructions or owner's manuals that accompany the vehicle or child restraint system at the time of first sale); or advice or direction to a dealer or distributor to cease the delivery or sale of specified models of vehicles or equipment.

II. The Petition for Reconsideration

The Alliance petitioned for reconsideration of the inclusion of ''advice or direction to a dealer or distributor to cease the delivery or sale of specified models of vehicles or equipment'' in the definition of ''other safety campaign.'' It cited our comments in the preamble to the final rule (67 FR at 63299) regarding our definition of ''customer satisfaction campaign * * *.'' in the early warning reporting final rule (67 FR 45822), in which we discussed our specific exclusion from that definition of ''advice or direction to a dealer or distributor to cease the delivery or sale of specified models of vehicles or equipment.'' At the end of this discussion, we stated ''We are adding the same exclusions to the definition of ''other safety campaign.'' We inadvertently omitted to do so by placing the closing parenthesis after ''sale'' rather than ''equipment.'' We are revising the definition of ''other safety campaign'' to expand the exclusion as we had originally intended. Thus, we grant the petition by the Alliance on this issue.

The Alliance also pointed out another instance in which the regulatory text did not reflect a statement made in the preamble of the final rule. There, we stated our intention to exempt from reporting ''any safety campaign involving substantially similar motor vehicle equipment that does not perform the same function in vehicles or equipment sold or offered for sale in the United States.'' 67 FR 63306. However, the regulatory text, at 49 CFR 579.11(d)(2), provides an exemption only if ''the component or system that gave rise to the foreign recall or other campaign does not perform the same function in any vehicles or equipment sold or offered for sale in the United

States.'' The Alliance asks that the phrase ''substantially similar'' be added before ''vehicles'' to reflect the preamble statement, and we are so doing.

III. The Initial List of Substantially Similar Vehicles and Equipment for 2003 Must Be Submitted No Later Than 30 Days After Publication of This Rule

Section 579.11(e) requires a manufacturer of motor vehicles to provide an annual list of vehicles that it sells or plans to sell in a foreign country that it believes are identical or substantially similar to motor vehicles it sells or offers for sale, or plans to sell, in the United States in the following year, which identifies each such identical or substantially similar vehicle sold or offered for sale in the United States. The list must be submitted to NHTSA not later than November 1 of each year, as we proposed in the NPRM. 66 FR at 51918.

However, we were unable to complete and publish the foreign defect reporting final rule until October 11, 2002, and it was not effective until 30 days after publication, November 12, 2002. Thus, the first November 1 following publication of the rule was 2002, but the first November 1 following its effective date is 2003. Some vehicle manufacturers phoned during October 2002, after publication of the final rule, to confirm that they would not have a legal reporting obligation as of November 1, 2002, and we confirmed that interpretation. However, the purposes of 49 U.S.C. 30166(l) cannot be fully realized if we defer submission of the initial list of substantially similar vehicles until November 1, 2003. A representative of the Alliance has informed us that most if not all of its member companies have been putting together such a list and could provide it within 30 days of publication of a notice requiring it. Thus, we are revising Section 579.11(e) to add a new sentence at the end, to read as follows:

> Not later than 30 days after January 28, 2003, each manufacturer to which this paragraph applies shall submit an initial annual list of vehicles for calendar year 2003 that meets the requirements of this paragraph.

IV. Reports May Be Submitted Electronically

In a telephone call, Michael Grossman asked on behalf of Automobili Lamborghini whether reports required by Section 579.11, Reporting responsibilities, could be submitted electronically. Section 579.6, Address for submitting reports and other information, contains both a general requirement that reports required by part 579 must be addressed to the Associate Administrator for Enforcement, and a specific requirement with respect to the information, documents, and reports that are to be submitted to NHTSA's early warning data depository under subpart C of part 579. However, it is silent on the manner in which reports are to be filed for purposes of foreign defect reporting.

With one exception, reports of foreign recalls and safety campaigns do not include copies of materials related to the manufacturer's foreign campaign, and are a manufacturer's compilation of the information required by the regulation. There is no reason why such a report may not be filed by ordinary mail, or by facsimile transmission, or e-mail (''electronically''). However, when a foreign government has ordered a manufacturer to conduct a campaign, the manufacturer must file a copy of that order with its report, and a translation as well if the foreign government's order is in a language other than English. We would accept a scanned copy of the order and translation attached to an e-mail report (as well as a hard copy by mail or fax). Accordingly, we are amending Section 579.6 to provide guidance for the electronic submission of foreign defect reports, with appropriate fax and e-mail addresses. These are respectively (202) 366–7882, and *foreign_recalls@nhtsa.dot.gov.* e-mail submissions under Section 579.5 should be sent to *tsb@nhtsa.dot.gov.*

V. Interpretation of ''Safety Guideline'

Section 579.4(c) defines ''safety recall,'' in part, as involving a ''failure to comply with an applicable safety standard or guideline.'' The Truck Manufacturers Association (TMA) asked for confirmation of its understanding that ''the agency incorporated the term guideline into this definition in order to accommodate any foreign country that may have applicable safety compliance rules that are not specifically identified as standards.''

As we noted in the preamble to the final rule, ''We proposed to characterize a 'safety recall' abroad as involving a determination * * * that there is a problem * * * that relates to motor vehicle safety (*e.g.*, a defect or noncompliance with a local safety standard or governmental guideline) * * * (p. 63298). There were no comments about the term ''guideline'' in the comments submitted on the NPRM for foreign defect campaign reporting. ''Standard'' is a broad term and is used in various ways in the United States. Manufacturers are required to comply with Federal motor vehicle safety standards, but are not required to comply with a Society of Automotive Engineers (SAE) standard (assuming that standard has not been incorporated by reference into the FMVSS). In that sense, the SAE standard is a ''guideline.'' We view TMA as essentially correct in interpreting the term as ''applicable safety compliance rules that are not specifically identified as standards.'' However, we do not find it necessary to define ''guideline'' because the important issue in this context is whether a campaign is being conducted because there has been a determination by the manufacturer or a foreign government that a safety guideline has not been met. The touchstone is the safety-relatedness of the problem to the standard or the guideline.

VI. Rulemaking Analyses

Executive Order 12866 and DOT Regulatory Policies and Procedures. This document was not reviewed under Executive Order 12866. It has been determined that the rulemaking action is not significant under Department of Transportation regulatory policies and procedures. *See* 67 FR 63309 for discussion of final rule.

Regulatory Flexibility Act. We have also considered the impacts of this rulemaking action in relation to the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). I certify that this rulemaking action does not have a significant economic impact upon a substantial number of small entities. *See* 67 FR 63309 for discussion of final rule.

Executive Order 13132 (Federalism). This final rule regulates the manufacturers of motor vehicles and motor vehicle equipment, will not have substantial direct effect 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, as specified in E.O. 13132.

Civil Justice Reform. This final rule will not have a retroactive or preemptive effect, and judicial review of it may be obtained pursuant to 5 U.S.C. 702. That section does not require that a petition for reconsideration be filed prior to seeking judicial review.

List of Subjects in 49 CFR Part 579

Imports, Motor vehicle safety, Motor vehicles, Reporting and recordkeeping requirements.

For the reasons set out in the preamble, 49 CFR part 579 is amended as follows:

PART 579—REPORTING OF INFORMATION AND COMMUNICATIONS ABOUT POTENTIAL DEFECTS

1. The authority citation for part 579 continues to read as follows:

Authority: Sec. 3, Pub. L. 106–414, 114 Stat. 1800 (49 U.S.C. 30102–103, 30112, 30117–121, 30166–167); delegation of authority at 49 CFR 1.50

2. Section 579.4 is revised by amending the term ''other safety campaign'' to read as follows:

§ 579.4 Terminology.

* * * * *

(c) Other terms. * * *

* * * * *

Other safety campaign means an action in which a manufacturer communicates with owners and/or dealers in a foreign country with respect to conditions under which motor vehicles or equipment should be operated, repaired, or replaced that relate to safety (excluding promotional and marketing materials, customer satisfaction surveys, and operating instructions or owner's manuals that accompany the vehicle or child restraint system at the time of first sale; or advice or direction to a dealer or distributor to cease the delivery or sale of specified models of vehicles or equipment).

* * * * *

3. Section 579.6 is revised to read as follows:

§ 579.6 Address for submitting reports and other information.

(a) Except as provided by paragraph (b) of this section, information, reports, and documents required to be submitted to NHTSA pursuant to this part may be submitted by mail, by facsimile, or by e-mail. If submitted by mail, they must be addressed to the Associate Administrator for Enforcement, National Highway Traffic Safety Administration (NHTSA), 400 7th Street, SW., Washington, DC 20590. If submitted by facsimile, they must be addressed to the Associate Administrator for Enforcement and transmitted to (202) 366–7882. If submitted by e-mail, submissions under subpart B of this part must be submitted to *foreign_recalls@nhtsa.dot.gov* and submissions under § 579.5 must be submitted to *tsb@nhtsa.dot.gov.*

(b) Information, documents and reports that are submitted to NHTSA's early warning data repository must be submitted in accordance with § 579.29 of this part. Submissions must be made by a means that permits the sender to verify that the report was in fact received by NHTSA and the day it was received by NHTSA.

4. Section 579.11(d)(2) is revised and paragraph (e) is amended by adding a sentence at the end thereof. The revision and amendment read as follows:

§ 579.11 Reporting responsibilities.

* * * * *

(d) Exemptions from reporting. * * *

* * * * *

(2) The component or system that gave rise to the foreign recall or other campaign does not perform the same function in any substantially similar vehicles or equipment sold or offered for sale in the United States; or

* * * * *

(e) Annual list of substantially similar vehicles. * * * Not later than 30 days after January 28, 2003, each manufacturer to which this paragraph applies shall submit an initial annual list of vehicles for calendar year 2003 that meets the requirements of this paragraph.

Issued on: January 16, 2003.

Jeffrey W. Runge,

Administrator.

[FR Doc. 03–1320 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 020409080–3013–07 ; I.D. 101802B]

RIN 0648–AP78

Magnuson-Stevens Fishery Conservation and Management Act Provisions; Fisheries of the Northeastern United States; Regulations Governing Northeast Multispecies and Monkfish Days-at-Sea

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Final rule.

SUMMARY: NMFS issues this final rule implementing a regulatory amendment to correct minor oversights in the August 1, 2002, interim final rule that implemented additional restrictions to reduce overfishing on species managed under the Northeast (NE) Multispecies Fishery Management Plan (FMP). The intent of this regulatory amendment is to revise monkfish days-at-sea (DAS) regulations in order to provide vessels possessing limited access Category C or D monkfish permits the opportunity to fish their full allocation of up to 40 monkfish DAS, regardless of the amount of NE multispecies DAS available to an individual vessel as of August 1, 2002. This regulatory amendment also revises ambiguous language to clarify that a vessel fishing under a Southern New England (SNE) and Mid-Atlantic (MA) Yellowtail Flounder Possession/Landing Letter of Authorization (LOA) may fish in the Gulf of Maine (GOM) or Georges Bank (GB) Regulated Mesh Areas (RMAs), provided the vessel abides by the more restrictive yellowtail flounder possession limits of the SNE and MA RMAs north of 40°00' N. lat.

DATES: Effective January 28, 2003.

ADDRESSES: Copies of the Regulatory Impact Review (RIR) prepared for this action are available from the Regional Administrator at the following address: National Marine Fisheries Service, 1 Blackburn Drive, Gloucester, MA 01930. This document is also accessible via the Internet at http://www.nero.nmfs.gov.

FOR FURTHER INFORMATION CONTACT: Allison Ferreira, Fishery Policy Analyst, phone: 978–281–9103, fax: 978–281–9135, e-mail: Allison.Ferreira@noaa.gov

SUPPLEMENTARY INFORMATION:

Background

NMFS published an interim final rule on August 1, 2002 (67 FR 50292), implementing the Settlement Agreement Among Certain Parties (Settlement Agreement), which was ordered by the U.S. District Court for the District of Columbia (Court) as a result of *Conservation Law Foundation et al.* v. *Evans et al.* The objective of the interim final rule was to reduce overfishing consistent with and pursuant to section 305(c)(3) of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act), while Amendment 13 to the FMP is being developed. However, following the publication of the interim final rule, some minor oversights in the rule became apparent. As a result, NMFS published a proposed rule (67 FR 70570) on November 25, 2002, for a regulatory amendment to correct these minor oversights.

The measures contained in this final rule are unchanged from those published in the proposed rule and are summarized in the following paragraphs. A complete discussion of the revisions being made to the August 1, 2002, interim final rule through this regulatory amendment, and the rationale for these revisions were

presented in the preamble to the proposed rule and are not repeated here.

The intent of the August 1, 2002, interim final rule was to provide vessels possessing limited access Category C or D monkfish permits with the opportunity to use their full annual allocation of 40 monkfish DAS, regardless of the number of NE multispecies DAS allocated under the Settlement Agreement. However, as currently written, the interim final rule specifies that Category C or D monkfish vessels that have been allocated fewer than 40 NE multispecies DAS may fish, as monkfish-only DAS (i.e., monkfish DAS that do not have to be fished concurrently with a NE multispecies DAS), those monkfish DAS equal to the difference between their NE multispecies DAS allocation and their monkfish DAS allocation for the fishing year May 1 through April 30. This does not account for vessels that used NE multispecies DAS prior to August 1, 2002, and, as a result, had fewer unused NE multispecies than unused monkfish DAS as of August 1, 2002. Therefore, NMFS, through this final rule, enables limited access Category C or D monkfish vessels to fish all of their allocated monkfish DAS that were unused as of August 1, 2002, regardless of how many NE multispecies DAS they had remaining as of August 1, 2002. This regulatory amendment modifies the monkfish DAS regulations found at § 648.92(b)(2), and applies to only the 2002 fishing year, which ends April 30, 2003. For the 2002 fishing year, this regulatory amendment authorizes a vessel to fish its monkfish-only DAS equal to the difference between the number of its unused monkfish DAS and its unused NE multispecies DAS as of August 1, 2002, in addition to the unused monkfish DAS associated with the vessel's unused NE multispecies DAS as of August 1, 2002. For the 2003 fishing year, vessels allocated fewer NE multispecies DAS than monkfish DAS would fish the difference in DAS as monkfish-only DAS, as stipulated in the August 1, 2002, interim final rule.

As under the current August 1, 2002, interim final rule, vessels fishing under a monkfish-only DAS will be required to fish under the same provisions as limited access Category A and B monkfish vessels. Limited access monkfish Category A and B vessels are required to fish their monkfish DAS in an existing monkfish exempted fishery, a fishery that has been demonstrated to result in less than a 5–percent bycatch of NE multispecies. The existing monkfish exemption areas are specified under § 648.81. A map of these exemption areas is also available from the Northeast Regional Office of NMFS (see **FOR FURTHER INFORMATION CONTACT**).

This regulatory amendment also revises ambiguous regulatory language pertaining to yellowtail flounder possession restrictions. The intent of the August 1, 2002, interim final rule was to allow vessels possessing a SNE and MA Yellowtail Flounder Possession/Landing LOA to fish any part of a trip in the GOM or GB RMAs, provided that they abide by the more restrictive yellowtail flounder possession limits of the SNE and MA RMAs north of 40o00' N. lat. However, this is not clearly stated in existing regulations pertaining to yellowtail flounder possession restrictions found at § 648.86(h)(2)(ii). Therefore, this action revises the regulatory language to clarify that vessels possessing a SNE and MA Yellowtail Flounder Possession/Landing LOA may fish in the GOM or GB RMAs under the more restrictive yellowtail possession limits of the SNE and MA RMAs.

NMFS will announce any continuation of the August 1, 2002, interim final rule by publishing notification in the **Federal Register**. Because this final rule amends that interim final rule, it will remain in effect for the duration of the August 1, 2002, interim final rule, including any continuation.

Comments and Responses

No public comments were received on the proposed rule.

Classification

The Administrator, Northeast Region, NMFS, determined that this regulatory amendment is necessary for the conservation and management of the NE multispecies and monkfish fisheries and that it is consistent with the Magnuson-Stevens Act and other applicable laws.

This final rule makes minor revisions to the regulations contained in the August 1, 2002, interim final rule in order to reflect NMFS' intent in implementing the Settlement Agreement. The interim final rule restricts a population of limited access Category C and D monkfish vessels' from using their full allocation of 40 monkfish DAS. This final rule relieves that restriction by permitting these vessels to utilize 40 monkfish DAS, regardless of the amount of NE multispecies DAS available as of August 1, 2002. It is imperative that this rule be effective immediately so that affected individuals can maximize the use of their monkfish DAS prior to the end of the fishing season on April 30, 2003. Therefore, because this rule relieves a restriction, the Assistant Administrator for Fisheries, NOAA, finds good cause under the Administrative Procedure Act pursuant to 5 U.S.C. 553 (d)(1) to waive the 30–day delay in effectiveness date for this final rule.

This final rule has been determined to be not significant for purposes of Executive Order 12866.

The Chief Counsel for 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. No comments were received regarding this certification. As a result, a regulatory flexibility analysis was not prepared.

List of Subjects in 50 CFR Part 648

Fisheries, Fishing, Reporting and recordkeeping requirements.

Dated: January 22, 2003

Rebecca Lent,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR part 648 is amended as follows:

PART 648—FISHERIES OF THE NORTHEASTERN UNITED STATES

1. The authority citation for part 648 continues to read as follows:

Authority: Authority: 16 U.S.C. 1801 *et seq.*

2. In § 648.86, paragraph (h)(2) (ii) is revised to read as follows:

§ 648.86 Multispecies possession restrictions.

* * * * *

(h) * * *

(2) * * *

(ii) The vessel does not fish south of 40°00' N. lat. for a minimum of 30 consecutive days (when fishing under the NE multispecies DAS program, or under the monkfish DAS program if the vessel is fishing under the limited access monkfish Category C or D provisions). Vessels subject to these restrictions may fish any portion of a trip in the GOM and GB Regulated Mesh Areas, provided the vessel complies with the possession restrictions specified under this paragraph (h). Vessels subject to these restrictions may also transit the SNE and MA Regulated Mesh Areas south of 40°00' N. lat., provided the gear is stowed in accordance with one of the provisions of § 648.23(b).

* * * * *

3. In § 648.92, paragraph (b)(2) is revised to read as follows:

§ 648.92 Effort-control program for monkfish limited access vessels.

* * * * *

(b) * * *

(2) *Category C and D limited access monkfish permit holders.* (i) *August 1, 2002 - April 30, 2003.* Each monkfish DAS used by a limited access multispecies or scallop vessel holding a Category C or D limited access monkfish permit shall also be counted as a multispecies or scallop DAS, as applicable, unless otherwise specified in this paragraph (b). A Category C or D vessel that had fewer unused multispecies DAS than unused monkfish DAS as of August 1, 2002, may fish under the limited access monkfish provisions for Category A or B vessels, as applicable, for the number of DAS that equal the difference between its unused monkfish DAS and unused multispecies DAS as of August 1, 2002. For such vessels, when the total allocation of multispecies DAS has been used, a monkfish DAS may be used without concurrent use of a multispecies DAS. (For example, if a monkfish Category D vessel has 10 NE multispecies DAS and 40 monkfish DAS remaining as of August 1, 2002, that vessel may use the remaining 30 monkfish DAS to fish on monkfish, without a NE multispecies DAS being used, once the remaining 10 NE multispecies DAS have been utilized. However, the vessel must fish the remaining 30 monkfish DAS under the regulations pertaining to a Category B vessel, and must not retain any regulated multispecies.)

(ii) *Beginning May 1, 2003.* Each monkfish DAS used by a limited access multispecies or scallop vessel holding a Category C or D limited access monkfish permit shall also be counted as a multispecies or scallop DAS, as applicable, except when a Category C or D vessel that has an allocation of multispecies DAS under § 648.82(l) that is less than the number of monkfish DAS allocated for the fishing year May 1 through April 30, that vessel may fish under the monkfish limited access Category A or B provisions, as applicable, for the number of DAS that equal the difference between the number of its allocated monkfish DAS and the number of its allocated multispecies DAS. For such vessels, when the total allocation of multispecies DAS have been used, a monkfish DAS may be used without concurrent use of a multispecies DAS. (For example, if a monkfish Category D vessel's multispecies DAS allocation is 30, and the vessel fished 30 monkfish DAS, 30 multispecies DAS would also be used. However, after all 30 multispecies DAS are used, the vessel may utilize its remaining 10 monkfish DAS to fish on monkfish, without a multispecies DAS being used, provided that the vessel fishes under the regulations pertaining to a Category B vessel and does not retain any regulated multispecies.)

* * * * *

[FR Doc. 03–1906 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 679

[Docket No. 021212306–2306–01; I.D. 012303B]

Fisheries of the Exclusive Economic Zone Off Alaska; Pollock in Statistical Area 610 of the Gulf of Alaska

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Closure.

SUMMARY: NMFS is prohibiting directed fishing for pollock in Statistical Area 610 of the Gulf of Alaska (GOA). This action is necessary to prevent exceeding the first seasonal allowance of the pollock interim total allowable catch (TAC) for Statistical Area 610 of the GOA.

DATES: Effective 1200 hrs, Alaska local time (A.l.t.), January 23, 2003, until superseded by the notice of Final 2003 Harvest Specifications of Groundfish for the GOA, which will be published in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: Mary Furuness, 907–586–7228.

SUPPLEMENTARY INFORMATION: NMFS manages the groundfish fishery in the GOA exclusive economic zone according to the Fishery Management Plan for Groundfish of the Gulf of Alaska (FMP) prepared by the North Pacific Fishery Management Council under authority of the Magnuson-Stevens Fishery Conservation and Management Act. Regulations governing fishing by U.S. vessels in accordance with the FMP appear at subpart H of 50 CFR part 600 and 50 CFR part 679.

The first seasonal allowance of the pollock interim TAC in Statistical Area 610 of the GOA is 2,916 metric tons (mt) as established by the interim 2003 harvest specifications for groundfish of the GOA (67 FR 78733, December 26, 2002).

In accordance with § 679.20(d)(1)(i), the Administrator, Alaska Region, NMFS (Regional Administrator), has determined that the first seasonal allowance of the pollock interim TAC in Statistical Area 610 will soon be reached. Therefore, the Regional Administrator is establishing a directed fishing allowance of 2,716 mt, and is setting aside the remaining 200 mt as bycatch to support other anticipated groundfish fisheries. In accordance with § 679.20(d)(1)(iii), the Regional Administrator finds that this directed fishing allowance will soon be reached. Consequently, NMFS is prohibiting directed fishing for pollock in Statistical Area 610 of the GOA.

Maximum retainable amounts may be found in the regulations at § 679.20(e) and (f).

Classification

This action responds to the best available information recently obtained from the fishery. The Assistant Administrator for Fisheries, NOAA, finds good cause to waive the requirement to provide prior notice and opportunity for public comment pursuant to the authority set forth at 5 U.S.C. 553(b)(B) as such requirement is contrary to the public interest. This requirement is contrary to the public interest as it would delay the closure of the fishery, lead to exceeding the interim TAC, and therefore reduce the public's ability to use and enjoy the fishery resource.

The Assistant Administrator for Fisheries, NOAA, also finds good cause to waive the 30–day delay in the effective date of this action under 5 U.S.C. 553(d)(3). This finding is based upon the reasons provided above for waiver of prior notice and opportunity for public comment.

This action is required by section 679.20 and is exempt from review under Executive Order 12866.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: January 23, 2003.

Dean Swanson,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 03–1905 Filed 1–23–03; 4:05 pm]

BILLING CODE 3510–22–S

Proposed Rules

Federal Register
Vol. 68, No. 18
Tuesday, January 28, 2003

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 TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2000–NM–409–AD]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 767–200, –300, and –300F Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Supplemental notice of proposed rulemaking; reopening of comment period.

SUMMARY: This document revises an earlier proposed airworthiness directive (AD), applicable to certain Boeing Model 767–200, –300, and –300F series airplanes, that would have required a one-time inspection for discrepancies of certain wire bundles in the forward cargo compartment, and corrective actions, if necessary. This new action revises the proposed rule by extending the compliance time and expanding the inspection area. The actions specified by this new proposed AD are intended to prevent damage to wire bundles, particularly those of the fuel quantity indication system (FQIS), which are located in the subject area. Damage of FQIS wires could cause arcing between those wires and power wires in the damaged wire bundle, and may lead to transmission of electrical energy into the fuel tank, which would result in a potential source of ignition in the fuel tank. This action is intended to address the identified unsafe condition.

DATES: Comments must be received by February 24, 2003.

ADDRESSES: Submit comments in triplicate to the Federal Aviation Administration (FAA), Transport Airplane Directorate, ANM–114, Attention: Rules Docket No. 2000–NM–409–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056. Comments may be inspected at this location between 9 a.m. and 3 p.m., Monday through Friday, except Federal holidays. Comments may be submitted via fax to (425) 227–1232. Comments may also be sent via the Internet using the following address: *9-anm-nprmcomment@faa.gov*. Comments sent via fax or the Internet must contain ''Docket No. 2000–NM–409–AD'' in the subject line and need not be submitted in triplicate. Comments sent via the Internet as attached electronic files must be formatted in Microsoft Word 97 for Windows or ASCII text.

The service information referenced in the proposed rule may be obtained from Boeing Commercial Airplane Group, P.O. Box 3707, Seattle, Washington 98124–2207. This information may be examined at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington.

FOR FURTHER INFORMATION CONTACT: Elias Natsiopoulos, Aerospace Engineer, Systems and Equipment Branch, ANM–130S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–1279; fax (425) 227–1181.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons are invited to participate in the making of the proposed rule by submitting such written data, views, or arguments as they may desire. Communications shall identify the Rules Docket number and be submitted in triplicate to the address specified above. All communications received on or before the closing date for comments, specified above, will be considered before taking action on the proposed rule. The proposals contained in this action may be changed in light of the comments received.

Submit comments using the following format:

- Organize comments issue-by-issue. For example, discuss a request to change the compliance time and a request to change the service bulletin reference as two separate issues.
- For each issue, state what specific change to the proposed AD is being requested.
- Include justification (*e.g.*, reasons or data) for each request.

Comments are specifically invited on the overall regulatory, economic, environmental, and energy aspects of the proposed rule. All comments submitted will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested persons. A report summarizing each FAA-public contact concerned with the substance of this proposal will be filed in the Rules Docket.

Commenters wishing the FAA to acknowledge receipt of their comments submitted in response to this action must submit a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket Number 2000–NM–409–AD.'' The postcard will be date stamped and returned to the commenter.

Availability of NPRMs

Any person may obtain a copy of this NPRM by submitting a request to the FAA, Transport Airplane Directorate, ANM–114, Attention: Rules Docket No. 2000–NM–409–AD, 1601 Lind Avenue, SW., Renton, Washington 98055–4056.

Discussion

A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to add an airworthiness directive (AD), applicable to certain Boeing Model 767–200, –300, and –300F series airplanes, was published as a notice of proposed rulemaking (NPRM) in the **Federal Register** on October 26, 2001 (66 FR 54171). That NPRM proposed to require a one-time inspection for discrepancies of certain wire bundles in the forward cargo compartment, and corrective actions, if necessary. That NPRM was prompted by a report indicating that, prior to engine start-up on a Boeing Model 767 series airplane, several circuit breakers tripped and the flight crew observed unusual messages on the engine indication and crew alerting system display. An investigation revealed that numerous wires in certain wire bundles had melted and burned. The affected wire bundles were located on the ceiling of the forward cargo compartment, and had chafed. Wires for the fuel quantity indication system (FQIS), which penetrate the fuel tank, are routed through one of the wire bundles that was damaged in the reported incident. Damage of FQIS wires could cause arcing between those wires and power wires in the damaged wire bundle, and may lead to transmission of electrical energy into the fuel tank, which would result in a potential source of ignition in the fuel tank.

Actions Since Issuance of Previous Proposal

Due consideration has been given to the comments received in response to the original NPRM. Some of the comments have resulted in changes to the original NPRM.

Support for the Original NPRM

One operator supports the original NPRM.

Request for Revised Service Information

One commenter, an operator, has identified three problems in Boeing Service Bulletin 767–24A0128, dated May 11, 2000, which was identified as the appropriate service information for the actions specified in the original NPRM. First, the Panduit strap does not fit into the cable spacer, as described in that service bulletin. Second, the specified 0.5-inch clearance between the wire bundles and the cargo liner is impossible to achieve. Third, the cargo liner panel is mislabeled in Figure 1, Sheet 2, of the service bulletin.

The FAA agrees. Boeing has revised the service bulletin, which the FAA has reviewed and approved. Boeing Service Bulletin 767–24A0128, Revision 2, dated May 23, 2002, addresses all of the commenter's concerns: The new Panduit straps will fit the cable spacers; the space requirements between the wire bundles and the cargo ceiling liner standoff have been revised to 0.25 inch for sleeving and 0.13 inch for sleeving and spacers; and Figure 1, Sheet 2, has been revised to identify the ''floor beam'' rather than the ''ceiling liner.'' The FAA has revised this supplemental NPRM to cite Revision 2 of the service bulletin as the appropriate service information for the proposed actions. Revision 2 of the service bulletin expands the inspection to include areas that were inadvertently omitted from the original service bulletin and Revision 1. Specifically, this supplemental NPRM would require inspection of wire bundles between right buttock line (RBL) 40 and RBL 70. (The original NPRM proposed to require inspection of bundles between RBL 40 and RBL 54.)

Request To Revise Cost Estimate

One commenter, an operator, recommends revising the Cost Impact section. Rather than 2 work hours to accomplish all the actions specified in the original NPRM, the commenter suggests that this figure be revised to 32 work hours per airplane, broken down as follows: 2 work hours to access the area, 2 work hours to inspect the wire bundles, 26 work hours to protect the wire bundles (the commenter reports finding inadequate clearance on the wire bundles on nearly all its airplanes and is adding protection to the bundles on each airplane), and 2 work hours for restoration.

The FAA partially agrees. Although moderating the clearance requirements (as described previously) would considerably reduce the time necessary to accomplish the corrective actions, only the inspection and clearance measurement of the wire bundles would actually be required by this supplemental NPRM. The economic analysis of an AD is limited to the cost of actions actually required by the rule. It does not consider the cost of conditional actions, which would be required to be accomplished—regardless of AD direction—to correct an unsafe condition identified on an airplane and to ensure operation of that airplane in an airworthy condition, as required by the Federal Aviation Regulations.

Request To Extend the Compliance Time

Two commenters, both operators, request that the compliance time be extended from 15 months to 18 months. One operator states that an 18-month compliance time would correspond to available maintenance opportunities for the fleet, based on the work-hour estimates, without compromising safety. The other operator requests that the compliance time reflect ATA ''Spec 111'' recommended guidelines for such non-emergency-related safety issues, and suggests that an 18-month compliance time would coincide with regularly scheduled ''C'' check visits.

The FAA agrees. In light of the revised work-hour estimates provided in Revision 2 of the service bulletin, the FAA finds that the proposed 18-month compliance time is more appropriate for the majority of operators to accomplish the corrective action that would be mandated by this supplemental NPRM and still ensure the safety of the fleet. This supplemental NPRM has been revised accordingly.

Request To Clarify Identity of Airplanes Subject to Inspection Requirement

One commenter, an operator, requests that the proposed AD be revised to clarify that only the inspection is required and operators may choose to rework the wire bundles if ''deemed necessary.'' The commenter requests that the difference between the service bulletin instructions and the AD inspection requirements be clearly defined.

The FAA partially agrees. The rework instructions in Revision 2 of the service bulletin correspond to the proposed requirements in this supplemental NPRM. However, the FAA disagrees with the request to require only the inspection of the wire bundles and to permit operators to determine whether corrective action is needed. The FAA finds that the need to rework the wire bundles is not a discretionary option for operators. If conditions exist that require the rework (as specified in this supplemental NPRM and clarified in Revision 2 of the service bulletin), then operators are required to comply with the rework requirements. The rework conditions proposed in this supplemental NPRM are the same as those recommended in Revision 2 of the service bulletin. No further change to this supplemental NPRM is necessary.

Conclusion

Revision 2 of the service bulletin specifies additional areas to be inspected. Since this change expands the scope of the original NPRM, the FAA has determined that it is necessary to reopen the comment period to provide additional opportunity for public comment.

Difference Between Service Bulletin and Proposed AD

The service bulletin recommends accomplishing the inspection ''at the earliest opportunity when manpower and facilities are available.'' However, the FAA has determined that such a compliance time will not ensure that operators address the unsafe condition in a timely manner. In developing an appropriate compliance time for this supplemental NPRM, we considered not only the manufacturer's recommendation, but the degree of urgency associated with addressing the subject unsafe condition, and the time necessary to accomplish the actions. In light of all of these factors, the FAA finds that an 18-month compliance time represents an appropriate length of time to allow affected airplanes to continue to be operated without compromising safety.

Clarification of Inspection Type

While the service bulletin specifies that operators ''inspect'' (for chafing or damage of wire bundles), this supplemental NPRM would require a ''detailed inspection.'' The FAA has determined that the procedures as described in the service bulletin should be considered a detailed inspection. Note 2 has been revised in this supplemental NPRM to define this type of inspection.

Cost Impact

There are approximately 774 airplanes of the affected design in the worldwide fleet. The FAA estimates that 303 airplanes of U.S. registry would be affected by this supplemental NPRM, that it would take approximately 2 work hours per airplane to accomplish the proposed inspection, and that the average labor rate is $60 per work hour. Based on these figures, the cost impact of this supplemental NPRM on U.S. operators is estimated to be $36,360, or $120 per airplane.

The cost impact figure discussed above is based on assumptions that no operator has yet accomplished any of the proposed requirements of this AD action, and that no operator would accomplish those actions in the future if this supplemental NPRM were not adopted. The cost impact figures discussed in AD rulemaking actions represent only the time necessary to perform the specific actions actually required by the AD. These figures typically do not include incidental costs, such as the time required to gain access and close up, planning time, or time necessitated by other administrative actions.

Regulatory Impact

The regulations proposed herein would not have a substantial direct effect 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, it is determined that this proposal would not have federalism implications under Executive Order 13132.

For the reasons discussed above, I certify that this proposed regulation (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) if promulgated, 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. A copy of the draft regulatory evaluation prepared for this action is contained in the Rules Docket. A copy of it may be obtained by contacting the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration proposes to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

Boeing: Docket 2000–NM–409–AD.

Applicability: Model 767–200, –300, and –300F series airplanes; certificated in any category; as listed in Boeing Alert Service Bulletin 767–24A0128, Revision 2, dated May 23, 2002.

Note 1: This AD applies to each airplane identified in the preceding applicability provision, regardless of whether it has been modified, altered, or repaired in the area subject to the requirements of this AD. For airplanes that have been modified, altered, or repaired so that the performance of the requirements of this AD is affected, the owner/operator must request approval for an alternative method of compliance in accordance with paragraph (b) of this AD. The request should include an assessment of the effect of the modification, alteration, or repair on the unsafe condition addressed by this AD; and, if the unsafe condition has not been eliminated, the request should include specific proposed actions to address it.

Compliance: Required as indicated, unless accomplished previously.

To prevent damage of wire bundles in the forward cargo compartment, particularly wires of the fuel quantity indication system (FQIS) installed in that area, which could cause arcing between the FQIS wires and power wires in the damaged wire bundle, lead to transmission of electrical energy into the fuel tank, and result in a potential source of ignition in the fuel tank, accomplish the following:

Inspection and Follow-on Actions

(a) Within 18 months after the effective date of this AD, do a one-time detailed inspection to detect discrepancies of all wire bundles routed along the ceiling of the forward cargo compartment from station 368 through 742 at right buttock lines 40 through 70, according to the Accomplishment Instructions of Boeing Alert Service Bulletin 767–24A0128, Revision 2, dated May 23, 2002. Discrepancies include chafing or damage of wire bundles near stand-offs that attach the cargo ceiling liner to the floor beams.

(1) Before further flight, repair any discrepancy, according to the Accomplishment Instructions of the service bulletin.

(2) Before further flight, examine the clearance between the wire bundles in the forward cargo compartment and the cargo liner standoffs, according to the service bulletin.

(i) If the clearance is greater than 0.25 inch: No further action is required by this AD.

(ii) If the clearance is 0.25 inch or less: Before further flight, install sleeving, cable spacers, and straps, as applicable, according to the Accomplishment Instructions of the service bulletin.

Note 2: For the purposes of this AD, a detailed inspection is defined as: ''An intensive visual examination of a specific structural area, system, installation, or assembly to detect damage, failure, or irregularity. Available lighting is normally supplemented with a direct source of good lighting at intensity deemed appropriate by the inspector. Inspection aids such as mirror, magnifying lenses, etc., may be used. Surface cleaning and elaborate access procedures may be required.''

Alternative Methods of Compliance

(b) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Seattle ACO.

Note 3: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Seattle ACO.

Special Flight Permits

(c) Special flight permits may be issued in accordance with §§ 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

Issued in Renton, Washington, on January 22, 2003.

Vi L. Lipski,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 03–1828 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 73

[Docket No. FAA–2002–13414; Airspace Docket No. 02–AGL–7]

RIN 2120–AA66

Proposed Modification of Restricted Areas R–6904A and R–6904B, Volk Field, WI

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This action proposes to raise the upper limit of Restricted Areas 6904A (R–6904A) and 6904B (R–6904B), Volk Field, WI, from 17,000 feet above

mean sea level (MSL) to Flight Level 230 (FL 230). Expanding the vertical limit would facilitate the transition of participating aircraft between these restricted areas and the overlying Volk West Air Traffic Control Assigned Airspace (ATCAA). The additional airspace is needed to fulfill new U.S. Air Force (USAF) training requirements. No other changes to R–6904A or R–6904B are proposed.

DATES: Comments must be received on or before March 14, 2003.

ADDRESSES: Send comments on this proposal to the Docket Management System, U.S. Department of Transportation, Room Plaza 401, 400 Seventh Street, SW., Washington, DC 20590–0001. You must identify the docket numbers FAA–2002–13414/ Airspace Docket No. 02–AGL–7 at the beginning of your comments.

You may also submit comments through the Internet to *http://dms.dot.gov.* You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Dockets Office (telephone 1–800–647–5527) is on the plaza level of the NASSIF Building at the Department of Transportation at the above address.

An informal docket may also be examined during normal business hours at the office of the Regional Air Traffic Division, Federal Aviation Administration, 2300 East Devon Avenue, Des Plaines, IL 60018.

FOR FURTHER INFORMATION CONTACT: Steve Rohring, Airspace and Rules Division, ATA–400, Office of Air Traffic Airspace Management, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone: (202) 267–8783.

SUPPLEMENTARY INFORMATION:

Comments 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 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 Docket Nos. FAA–2002–13414/Airspace Docket No. 02–AGL–7.'' 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 be filed in the docket.

Availability of NPRM's

An electronic copy of this document may be downloaded through the internet at *http://dms.dot.gov.*

Additionally, any person may obtain a copy of this notice by submitting a request to the Federal Aviation Administration, Office of Air Traffic Airspace Management, ATA–400, 800 Independence Avenue, SW., Washington, DC 20591, or by calling (202) 267–8783. Communications must identify both docket numbers 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, which describes the application procedure.

Background

By letter, the USAF requested that the FAA take action to increase the vertical limits of R–6904A and R–6904B from 17,000 feet above MSL to FL 230. Currently, participating aircraft must change their flight profile when crossing the 1,000 feet of airspace located above the restricted areas and below the Volk West ATCAA. This requested action would facilitate the transition of participating aircraft between these restricted areas and the overlying Volk West ATCAA by eliminating the 1,000-foot gap between the restricted areas and the ATCAA. This proposed action would also provide additional airspace needed to fulfill new USAF training requirements. Specifically, new training requirements call for practicing the release of bombs from higher altitudes than are currently available within the existing airspace structure. The current upper limit of 17,000 feet above MSL is not suitable for meeting this new training requirement. Raising the ceiling to FL 230 would allow for the required practice. No other changes to R–6904A or R–6904B are requested.

The Proposal

The FAA is proposing an amendment to 14 CFR part 73 to raise the vertical limits of R–6904A and R–6904B from 17,000 feet above MSL to FL 230. This additional altitude is required to eliminate the 1,000-foot gap between the restricted areas and the overlying Volk West ATCAA, and to meet the Air Force's requirement to practice the release of bombs from higher altitudes than are currently available within the existing restricted area airspace. No other changes to R–6904A or R–6904B are proposed.

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, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

This proposal will be subjected to an environmental analysis in accordance with FAA Order 1050.1D, Procedures for Handling Environmental Impacts, prior to any FAA final regulatory action.

List of Subjects in 14 CFR Part 73

Airspace, Navigation (air).

The Proposed Amendment

In consideration of the foregoing, the Federal Aviation Administration proposes to amend 14 CFR part 73 as follows:

PART 73—SPECIAL USE AIRSPACE

1. The authority citation for part 73 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.

§ 73.63 [Amended]

2. § 73.63 is amended as follows:

* * * * *

R–6904A Volk Field, WI [Amended]

By removing the current designated altitudes and substituting the following:

Designated altitudes. 150 feet AGL to FL 230.

* * * * *

R–6904B Volk Field, WI [Amended]

By removing the current designated altitudes and substituting the following:

Designated altitudes. Surface to FL 230.

* * * * *

Issued in Washington, DC on January 21, 2003.

Reginald C. Matthews,

Manager, Airspace and Rules Division.

[FR Doc. 03–1874 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 157

[Docket Nos. RM03–4–000 and AD02–14–000]

Emergency Reconstruction of Interstate Natural Gas Facilities Under the Natural Gas Act

January 17, 2003.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations to enable natural gas interstate pipeline companies to replace mainline facilities using a route other than the existing right-of-way, and to commence construction without being subject to the 45-day prior notice proceedings specified in the Commission's regulations and without project cost constraints, when immediate action is required to restore service in an emergency due to a sudden unanticipated loss of natural gas or capacity in order to prevent loss of life, impairment of health, or damage to property. In addition, the Commission is proposing to revise reporting requirements so that a natural gas company, acting under part 157 in responding to an emergency, would submit a description of its activities to the Commission prospectively, in advance of commencing construction, rather than retrospectively, as is currently the case. An important objective of the proposed rule is the reconciliation of the Commission's regulatory responsibilities under its enabling statutes and federal environmental and safety laws with the need to protect persons and property. The Commission requests that comments address the adequacy of the proposed expansion of pipeline companies' authority under their part 157 blanket certificates in situations where immediate action is necessary to reconstruct interstate pipeline facilities that have been destroyed or compromised by a sudden unanticipated natural event or deliberate effort to disrupt the flow of natural gas or whether there is a need for further action by the Commission or Congress.

DATES: Comments are due February 27, 2003.

ADDRESSES: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT: Robert Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, (202) 502–6022.

Gordon Wagner, Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, (202) 502–8947.

Berne Mosley, Office of Energy Projects, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, (202) 502–8625.

SUPPLEMENTARY INFORMATION:

1. The Federal Energy Regulatory Commission (Commission) is proposing to amend part 157, subpart F, of its regulations to enable natural gas interstate pipeline companies to replace mainline facilities using a route other than the existing right-of-way, and to commence construction without being subject to the 45-day prior notice proceedings specified in § 157.205 of the Commission's regulations and without project cost constraints, when immediate action is required to restore service in an emergency due to a sudden unanticipated loss of natural gas or capacity in order to prevent loss of life, impairment of health, or damage to property. In addition, the Commission is proposing to revise reporting requirements so that a natural gas company, acting under part 157 in responding to an emergency, would submit a description of its activities to the Commission prospectively, in advance of commencing construction, rather than retrospectively, as is currently the case. An important objective of the proposed rule is the reconciliation of the Commission's regulatory responsibilities under its enabling statutes and federal environmental and safety laws with the need to protect persons and property.

Background

2. On April 22, 2002, staff from the Commission and from the Department of Transportation (DOT) Office of Pipeline Safety (OPS) jointly convened a technical conference to consider whether to, or how to, clarify, expedite, and streamline permitting and approvals for interstate pipeline reconstruction following a sudden unanticipated service disruption.[1] Efforts to ensure the security of the nation's energy infrastructure have generally focused on maintaining the physical integrity of facilities and preparing to respond to accidents, such as excavation that breeches a buried pipe, natural disasters, such as earthquakes and landslides, and foreseeable equipment failure. The conference broadened this focus to consider how best to respond to damage due to a deliberate effort to disrupt the flow of natural gas.

3. At the conference, Commission and OPS staff provided an overview of current regulatory processes and presented examples of recent natural gas emergencies. Conference participants—representing federal, state, and local agencies, energy industry sectors, trade groups, and interested individuals—suggested various means to speed the reconstruction of interstate gas facilities, including: revising existing legislative mandates, revising Commission regulations, and enhancing coordination among federal, state, and local entities. A transcript of the conference and the comments subsequently submitted are contained in the record in Docket No. AD02–14–000.[2]

[1] On the following day, staff from the Commission and from the Department of Energy (DOE) jointly convened a technical conference to consider whether to or how to clarify, expedite, and streamline the reallocation of gas supplies in the event of a sudden unanticipated service disruption. That proceeding, in Docket No. AD02–15–000, is not addressed here.

[2] The conference comments are available on FERC's Web site at *http://ferc.gov* using the Federal Energy Regulatory Records and Information System (FERRIS) to access filings in Docket No. AD02–14–000. The Interstate Natural Gas Association of America (INGAA) submitted scenarios describing how interstate pipelines might respond to various types of facility-related emergencies. Because of security concerns associated with disclosing this information, these scenarios are not included in the public record in Docket No. AD02–14–000; however, while the particulars of the scenarios are not described in detail in the public record, the results are discussed in general.

4. In general, staff found the Commission's existing authorities and policies sufficient, and sufficiently flexible, to enable pipelines to respond to emergencies in a timely manner. However, following consideration of the April 2002 conference's presentations, discussions, and comments, the Commission has identified circumstances under which its present practices could constrain a pipeline from initiating a timely response. Accordingly, as discussed below, the Commission proposes to amend its regulations concerning blanket certificates.

Discussion

The Commission's Existing Authority

5. In the normal course of events, an interstate gas pipeline seeking to build new facilities, or rebuild existing facilities, will file an application with the Commission pursuant to section 7(c) of the Natural Gas Act (NGA) for authorization for the proposed construction. The Commission reviews the application, considers comments in favor of and opposed to the proposal, and assesses economic and environmental impacts. The time required to ensure that all views receive a full hearing, and all impacts are adequately assessed, varies with the complexity of the project proposed. The time needed to reach a final determination on an application is typically measured in months. Consequently, the standard NGA section 7(c) certification process is not suited to an emergency situation that requires an immediate response to prevent loss of life, impairment of health, or damage to property.

6. In establishing the initial framework for federal regulation of the natural gas industry, the NGA explicitly recognized the need to provide for a rapid response to an emergency. NGA section 7(c)(1)(B) states that ''the Commission may issue a temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular customers, without notice or hearing, pending the determination of an application of a certificate.'' The Commission has issued temporary certificates in response to companies' requests for authorization to undertake various activities on an emergency basis, with temporary authorization valid until the Commission acts on an application for permanent authorization. Natural gas companies have received temporary emergency authorization to build new facilities, modify existing facilities, alter operational parameters, and change rates.[3] Section 2.57 of the Commission's regulations states that temporary certificates should be employed for minor enlargements or extensions of existing facilities, and not for construction ''of major proportions.''[4]

7. In addition to the NGA's statutory emergency provision, the Commission's regulations permit pipelines to undertake limited construction projects without waiting for NGA section 7(c) case specific certificate authorization. For example, section 2.55 of the Commission's regulations permits pipeline companies to replace or refurbish deteriorating facilities and make minor upgrades to facilities without first obtaining an NGA section 7(c) certificate. Thus, if facilities are damaged or become inoperable for any reason, a pipeline could, pursuant to section 2.55, undertake repairs or replacement as necessary to restore service. However, section 2.55 is limited to returning a facility to its original service capacity; it does not apply to efforts that will expand or eliminate existing services. Further, section 2.55 applies only to new facilities located within the same right-of-way or at the same site as the existing facilities. Finally, certain auxiliary facilities, and replacement facilities projected to cost more than $7,500,000, are subject to a 30-day prior notice.[5]

8. If gas facilities are damaged, and a subsequent investigation of the event or contamination of the area restricts access to the damage site, we expect section 2.55 would prove ineffective if rapid reconstruction is required to restore service. In such circumstances, a company would be compelled to reroute around its damaged facilities, which would require construction outside the footprint of the existing facilities' right-of-way. Construction beyond the bounds of the existing right-of-way, and even construction within the existing right-of-way that uses temporary workspace other than that used to construct the original facility, is barred by section 2.55.[6]

9. Section 2.55 of the Commission's regulations serves, in effect, as standing authorization for pipelines to perform periodic maintenance and routine replacement. Given section 2.55's inherent limitations on the type of and location of facilities permitted, and the potential to trigger a 30-day prior notice delay, we believe that section 2.55 cannot always serve to ensure a prompt response to sudden unanticipated service disruptions. In particular, section 2.55 is inapplicable if construction outside of the existing right-of-way is needed.[7] Section 2.55 is best suited to its intended use, that being the replacement of physically deteriorated or obsolete facilities and the installation of auxiliary or appurtenant facilities to enhance operations, such as valves, pigging facilities, or communication equipment.

10. The blanket authority conferred by part 157, subpart F, of the regulations provides another vehicle for reconstruction of facilities in an emergency, but this authority is also limited. Virtually all existing interstate gas pipelines hold blanket certificates allowing them to acquire, operate, abandon, replace, and rearrange certain facilities. Acting under blanket authority, a pipeline may install new facilities on a new right-of-way, which may be acquired through the pipeline's exercise of eminent domain. However, blanket authority is limited to projects costing no more than $21,000,000.[8] Further, blanket authority does not apply to projects that alter or add mainline loop line, or extend a mainline, or increase compression to boost mainline capacity. An important

[3] *See, e.g.*, Texas-Ohio Pipeline, Inc., 58 FERC ¶ 61,025 (1992) (order issuing temporary certificate) and 69 FERC ¶ 61,145 (1994) (order issuing permanent certificate).

[4] In *Pennsylvania Gas and Water Company* v. *FPC,* 427 F.2d 568, 574 (D.C. Cir. 1970), the court reviewed the legislative history of the section 7 temporary certificate provision, and found it ''was meant to cover a narrow class of situations, to permit temporary and limited interconnection, or expansion of existing facilities in order to meet such emergencies as breakdowns in the service of operating natural gas companies, or sudden unanticipated demands.'' *Citing* Algonquin Gas Transmission Company v. FPC, 201 F.2d 334 (1st Cir. 1953). *See also* Mississippi River Transmission Corporation, 40 FPC 190 (1968).

[5] This amount is adjusted annually. *See* 18 CFR 157.208(d) (2002), Table 1, column 1. Advance notice for replacement facilities that exceed the current $7.5 million cost limit of 18 CFR 157.208(d) must include maps and a description of the erosion control, revegetation and maintenance, and stream and wetland crossings procedures. This prior notice would not apply if DOT safety regulations required that the replacement activity be performed immediately.

[6] *See* 18 CFR § 2.55(b) (2002), Appendix A to part 2, Guidance for Determining the Acceptable Construction Area for Replacements, specifies the criteria that must be met in order to proceed under section 2.55(b), and cautions that ''[i]f these guidelines cannot be met,'' and no exemption is applicable, ''construction authorization must be obtained pursuant to another regulation under the Natural Gas Act.''

[7] The scope of section 2.55 is expanded in section 2.60 to include the installation and modification of ''defense-related facilities,'' such as emergency company headquarters, emergency communications equipment, and fallout shelters at compressor stations. However, as a practical matter, the Commission does not expect this particular provision to ameliorate the other section 2.55 constraints that render these regulations unsuitable as a vehicle to recover from accidental or intentional damage.

[8] This amount is adjusted annually. By way of contrast, section 2.55 has no such project cost cap.

exception to this limitation applies to mainline, lateral, and compressor replacements that do not qualify under 2.55(b) because they will result in an incidental increase in capacity [9] or because they cannot satisfy the location or workspace requirements of section 2.55(b).[10]

11. In other words, part 157, subpart F, permits replacement construction that uses temporary workspace beyond the bounds of the temporary workspace previously used to construct the original facilities as necessary to install replacement facilities. These regulations also permit locating a portion of mainline, lateral, or compressor replacement facilities outside, but presumably adjacent to, an existing right-of-way where, for whatever reason, the new facilities could not be placed entirely within the original facilities' existing right-of-way. These regulations, however, do not appear to contemplate mainline construction over an entirely different route as may be necessary to circumvent the site of a disaster if immediate replacement is necessary before the original site is again available.

12. In addition, part 157 blanket authorization, although granted automatically, is subject to compliance with standard conditions, in particular, the environmental criteria specified in § 157.206(d) and the reporting requirements of § 157.207. Any project undertaken pursuant to blanket authority that will exceed $7,500,000 in costs is subject to a 45-day prior notice requirement.[11] If a protest to a proposal is submitted during this time, and the project sponsor is unable to resolve the objection within another 30 days, then instead of proceeding under blanket authority, the prior notice filing is treated as an application for section 7(c) certificate authorization.

13. While section 2.55 and part 157 of the Commission's regulations are commonly employed for routine business activities, part 284, subpart I, of the regulations applies only in an emergency.[12] Under part 284, a pipeline may extend its facilities, interconnect with other pipelines, sell gas as needed to maintain adequate service or serve particular customers, and increase gas deliveries in order to meet weather-induced demand. However, approval for facilities and services under part 284 is provisional; the regulations only apply to actions that are anticipated to last no longer than 60 days,[13] since it is expected that the pipeline will be able to reconstitute service within this time frame or will seek another source of authorization for its actions.[14] Although part 284 places no explicit limitation on the types of facilities or transactions covered, these regulations have not been viewed as applicable to long-term or large-scale undertakings. In practice, these emergency regulations have typically been used for small-scale efforts, such as installing a tap. Also, the part 284 emergency regulations do not provide the pipeline with the right to acquire easements by means of eminent domain.

Issues Regarding the Commission's Existing Authority

14. The Commission believes that its existing authority is adequate to manage a timely response to most foreseeable types of emergencies caused by damage to gas facilities.[15] Conference participants, however, have identified certain circumstances that could inhibit a timely response. We are persuaded that if facilities sustain sudden, significant, unanticipated damage, and restoring service requires construction of mainline facilities over a new right-of-way, our existing regulations may not always allow for arapid or sufficiently expansive response to such an emergency.

15. INGAA urges the Commission to take the lead in expediting emergency permits and authorizing necessary facilities. INGAA proposes that the Commission, following notification by a pipeline that an emergency exists, authorize the replacement of facilities as necessary to restore service, whether within or outside of an existing right-of-way. INGAA suggests the Commission consider including a certificate or tariff provision to authorize emergency construction outside of an existing right-of-way. INGAA does not propose that this provision be self implementing, but rather suggests that it be subject to the Director of Energy Projects finding that an emergency exists and the Commission finding the actions of the pipeline to be appropriate.

16. A representative of Pennsylvania's Public Utility Commission recommends that the Commission require pipelines to incorporate an emergency response plan as a condition of a certificate, and that as part of a certificate authorization, the Commission grant waivers for certain operations in the event of specific service interruptions, such as authorization to establish a new right-of-way to detour around a damaged facility site when necessary to expedite restoration. Conference participants suggest that the Commission amend its part 284 emergency regulations to allow for actions that last longer than the current 60-day limit.

17. Several participants at the April 2002 conference stress the need to plan for and to coordinate the efforts of local, state, and federal authorities to respond to an emergency, and suggest the Commission take the lead in this effort.[16] In large part, events have effectively overtaken such suggestions. In May 2002, DOE created an Office of Energy Assurance, charged with the mission of working in close collaboration with local and state governments and the private sector to guard against and respond to energy disruptions. The Office of Energy Assurance has formed a team composed of DOE personnel, DOE laboratories and facilities, other federal agencies, local and state officials, and the owners and operators of the energy infrastructure. This team's task is to identify critical components and interdependencies of the energy system, identify threats to the system, recommend actions to correct or mitigate vulnerabilities, plan for response and recovery in the event of disruptions, and provide technical response support during emergencies.

18. The Office of Energy Assurance's statement of mission and goals indicate that it will function as the federal managerial focal point for: Activities involving the location and content of

[9] Incremental increases in mainline capacity that occur incidental to facilities' modifications undertaken for sound engineering purposes are permitted. 18 CFR 157.202(b)(2)(i) (2002).

[10] 18 CFR 157.202(b)(2) (2002).

[11] 18 CFR 157.205 (2002). Further, before initiating construction or easement negotiations, a pipeline company seeking to act under blanket authorization is expected to make a good faith effort to provide 30-day prior notice to all affected landowners. 18 CFR § 157.203(d) (2002).

[12] ''Emergency'' is defined as an actual or expected shortage of gas supply or capacity that would disrupt existing service; a sudden unanticipated loss of gas supply or capacity; an anticipated loss of gas supply or capacity due to a foreseeable facility outage resulting from a natural disaster beyond the company's control; or a situation in which the company determines that immediate action is needed or will be needed to protect life, health, or property.

[13] A single, additional 60-day extension may be requested. Although the part 284, Subpart I, regulations may exempt a gas company, Hinshaw pipeline, or intrastate pipeline from NGA section 7 jurisdiction in order to respond to an emergency, if emergency conditions persist beyond 120 days (60 days plus a 60-day extension), then an NGA section 7(c) certificate would be required for permanent authority to continue operations.

[14] *See, e.g.*, Northern Natural Gas Company, 64 FERC ¶ 61,187, at 62,562–63 (1993).

[15] The Commission requested comments on whether it would be prudent to prepare for emergencies by directing pipelines to build redundant facilities. No participant endorsed this approach.

[16] For example, several comments propose the formation of an interagency crisis task force, made up of representatives of local, state, and federal agencies, charged with coordinating and expediting emergency response and recovery.

equipment stockpiles; overseeing industry mutual aid pooling and exchange programs; identifying critical facilities, equipment, and personnel; establishing communications protocol; and developing security and contingency plans.[17]

19. On November 13, 2002, the President signed into law the Homeland Security Act of 2002. Among other things, that law establishes that within the Department of Homeland Security the Undersecretary of Emergency Preparedness and Response will be responsible for coordinating federal response resources in the event of a terrorist attack or other disaster. In light of these developments, the Commission concludes that it can best support intra- and inter-governmental and industry coordination by contributing to and participating in the efforts of the Department of Homeland Security and DOE's Office of Energy Assurance.

20. The regulatory amendments proposed herein are limited in that they do not address sudden, yet unanticipated, loss of gas or capacity attributable to safety concerns. Nevertheless, we note that section 16(a)(1) of the Pipeline Safety Improvement Act of 2002 establishes an interagency committee, headed by the Council on Environmental Quality (CEQ), with the Commission among its members, ''to develop and ensure implementation of a coordinated environmental review and permitting process in order to enable pipeline operators to commence and complete all activities necessary to carry our pipeline repairs'' expeditiously. To the extent further changes to the Commission's rules may be necessary to address safety concerns, we expect the interagency committee called for by this Act will provide a vehicle for identifying the relevant issues.

Proposed Regulations

21. To allow pipelines to expedite recovery following an emergency due to a sudden unanticipated loss of gas or capacity that threatens life, health, or property, the Commission is proposing to expand the scope of construction permitted under the blanket certificate authority of part 157, subpart F, of its regulations. One issue conference participants raised repeatedly was the prospect that if mainline facilities are damaged, and the facility owner's access to the damaged site is temporarily restricted, no regulatory remedy now exists to ensure the rapid restoration of service. The logical alternative to repairing facilities at the point of damage would be to build around that point. The Commission's section 2.55 regulations do not allow replacement and repair activities to take place outside of facilities' original right-of-way, and so preclude any such rerouting. As explained, part 157 is less restrictive, but still does not permit the extensive deviation from an existing right-of-way that would presumably be necessary to circumvent a restricted or quarantined area. Accordingly, we propose expanding part 157 to permit pipeline companies to establish new rights-of-way around an accident site in order to reconnect a severed mainline or to construct other facilities as needed to restore service. Further, to the extent that a pipeline company could compensate for damage to one portion of its system by rearranging gas flows or increasing throughput on an unaffected portion of its system, we propose to place such system modifications within the category of ''eligible facilities.''

22. As is, part 157 blanket authorization only applies to a limited set of ''eligible facilities,'' and specifically excludes the extension, expansion, or looping of a mainline.[18] As noted above, this restriction was broadened incrementally in 1999 to include mainline replacements undertaken for sound engineering reasons that either created an incidental increase in mainline capacity or did not lie within the original facilities' footprint, and consequently were outside of the section 2.55(b) replacement parameters.[19] However, this modification in the breadth of eligible facilities did not contemplate the more extensive rerouting that would be required to reach around a cordoned accident area.[20] We request comments on amending § 157.202 of our regulations to allow a pipeline to reconstitute disrupted service by routing around, laying loop line along, or boosting compression on a damaged mainline.

23. This proposal is not intended as an open-ended expansion of existing blanket authority. The enlargement of the scope of permissible actions under part 157, subpart F, is restricted to actions necessary to restore service after an interruption due to an emergency event. By way of contrast, if hydrostatic testing discloses a structural weakness in a pipeline, while this weakness has the potential to cause an interruption in service, unless the pipeline has actually ruptured, these circumstances would not qualify as an emergency, as there would be no sudden unanticipated loss of gas or capacity. Accordingly, the pipeline company would be expected to act under other existing authority, such as section 2.55 of our regulations, to rectify the identified structural weakness. Similarly, part 157 would not apply to system modifications that boosted compression or mainline capacity unless the increase was undertaken as part of a program to restore service cut off as a consequence of an event resulting in a sudden unanticipated loss of gas or capacity.

24. We propose to expand the ''eligible facility'' definition by amending the last line of § 157.202(b)(2)(i) as follows: ''Replacements for the primary purpose of creating additional main line capacity are not eligible facilities; however, replacements for the primary purpose of restoring service to prevent loss of life, impairment of health, or damage to property due to sudden unanticipated damage to main line facilities are eligible facilities.'' In addition, we propose to amend § 157.202(b)(2)(ii)(C), which lists certain exclusions from eligible facilities, to clarify that facilities, including looping and compression, that alter the capacity of a mainline, when necessary to reconstitute service after sudden unanticipated damage to a mainline, will be considered replacement facilities for the primary purpose of restoring service, and be defined as eligible facilities. Specifically, we propose to revise § 157.202(b)(2)(ii)(C) to read as follows: ''A facility, including compression and looping, that alters the capacity of a main line, except replacement facilities covered under § 157.202(b)(2)(i).''

25. We believe this expanded blanket authority fills a gap that now confronts a pipeline unable to initiate recovery efforts when (1) section 2.55 of the regulations is inapplicable because of the need to construct outside the footprint of the existing facilities, (2) the

[17] In the event of an emergency, numerous entities will be required to coordinate communications and actions. To facilitate recovery efforts, the Commission will make available via its Web site a list of the entities likely to be involved in these efforts.

[18] 18 CFR 157.202(b)(2)(ii)(B) and (C) (2002).

[19] Order No. 603, FERC Stats. & Regs. ¶ 31,073, at 30,791–94 (1999).

[20] Order No. 603 envisioned replacements such as ''a section of deteriorated or obsolete 18-inch pipe located between existing 20-inch sections,'' where replacing the 18-inch pipe with a larger 20-inch segment would serve the sound engineering purpose of making pigging the combined stretch of pipe possible. Order No. 603 also recognized the need to grant natural gas companies the flexibility to act under blanket certificate authority to replace facilities where construction of new facilities might spill over the original temporary workspace or permanent right-of-way. Nothing in Order No. 603 envisioned replacement of facilities outside the existing right-of-way by the creation of an entirely new route due to the need to circumvent an accident site.

part 284, subpart I, emergency provisions are insufficient because the anticipated duration of the reconstruction effort will be longer than 60 days, or (3) new facilities needed to restore service are not permitted under the existing part 157, subpart F, regulations because the new facilities would expand capacity on, extend, or loop a mainline. Although the proposed revisions enlarge the § 157.202 definition of eligible facilities, other constraints on construction under blanket authority remain.

26. Among these other applicable constraints are regulations governing prior notice requirements, project cost limits, reporting requirements, and the standard conditions of § 157.206, covering environmental compliance. While environmental compliance with certain statutory requirements lies beyond the Commission's jurisdictional purview, and is thus beyond our discretion to affect, we can act on our own to modify compliance with our own regulations. We propose to do so by removing prior notice and project cost limit requirements to permit a company to act under blanket authority to respond to an emergency caused by a sudden unanticipated loss of gas or capacity that threatens life, health, or property.

27. Provided a project meets the relevant part 157 criteria, and will cost no more than $7.5 million,[21] blanket authorization is automatic, and construction can commence at the sponsoring company's discretion. However, projects expected to exceed $7.5 million are subject to a 45-day prior notice provision, pursuant to § 157.205(a). We propose to modify § 157.205(a) to provide an exception to these prior notice proceedings for emergency reconstruction, inserting the phrase ''except for activity required to restore service to prevent loss of life, impairment of health, or damage to property in an emergency due to a sudden unanticipated loss of natural gas supply or capacity,'' as follows: ''No activity described in §§ 157.208(b), 157.211(a)(2), 157.214 or 157.216(b), except for activity required to restore service in an emergency due to a sudden unanticipated loss of natural gas supply or capacity, is authorized by a blanket certificate granted under this subpart, unless, prior to undertaking such activity'' notice requirements are fulfilled. This proposed qualification presumes that in an emergency, the public interest in rectifying service at the earliest possible date will outweigh the public benefit of providing 45-day advance notice of planned reconstruction.

28. We note that although this proposed amendment will omit the prior 45-day public notice requirement of § 157.205(a) in an emergency, we retain the separate prior landowner notice requirement of § 157.203(d). Section 157.203(d) directs a company to make a good faith effort to notify all affected landowners 30 days prior to commencing construction. We expect a company that seeks to build around an accident site, as part of the process of considering alternative routes, will make a good faith effort to identify and inform affected landowners in advance of any new construction. Given the process involved in acquiring new easements, and given that landowners, to which pipeline companies must give 30-days notice pursuant to the Commission's landowner notification requirements, may agree to waive the remainder of that 30-day notice period, we do not expect this prior landowner notice provision to impede a company's capability to commence emergency reconstruction activities. The Commission recognizes that there may be instances where timely reconstruction of facilities could be delayed by companies' inability to obtain landowners' agreement to waive the remainder of the 30-notice period. In such instances, the Commission will consider requests to waive the remainder of the 30-day notice period.

29. Even with mainline rerouting without prior notice, action under blanket authority would be thwarted if emergency reconstruction expenses were to exceed the part 157 project cost limit. Accordingly, we propose to lift the project cost cap for emergency response efforts. This proposed exemption is not to be interpreted as an invitation to undertake open-ended system expansions; it applies exclusively to emergency response projects, and extends only as far as is necessary to restore service to pre-emergency capacity levels.[22] Therefore, we propose to amend § 157.208(a) to provide for automatic authorization for emergency reconstruction, without any restriction on project cost, by interjecting the phrase ''or if the project is required to restore service to prevent loss of life, impairment of health, or damage to property in an emergency due to a sudden unanticipated loss of natural gas supply or capacity'' as follows:

> If the project cost does not exceed the cost limitations set forth in column 1 of Table I, under paragraph (d) of this section, or if the project is required to restore service in an emergency due to a sudden unanticipated loss of natural gas supply or capacity, the certificate holder is authorized to make miscellaneous rearrangements of any facility, or acquire, construct, replace, or operate any eligible facility.

30. In an emergency, the Commission expects to make, and expects affected pipelines to make, every reasonable effort to restore essential service as rapidly as possible. We believe these proposed amendments to part 157 offer the best way to authorize emergency reconstruction, particularly in view of the comparatively sparse use of and ambiguities that remain regarding the scope of the part 284 emergency provisions. As noted , this proposed expanded blanket authority will apply only when acting in response to an emergency due to a sudden unanticipated loss of gas supply or capacity that threatens life, health, or property.[23]

31. Under the standard part 157.207 reporting requirements, a company submits an annual report—a compilation describing projects completed pursuant to blanket authority during the year. Since we are proposing to provide self-implementing automatic authorization for emergency reconstruction and to omit prior notice for emergency reconstruction, we find it prudent to require, in addition to an annual report, that companies relying

[21] As previously noted, this amount is adjusted annually, and appears in Table 1, column 1, of 18 CFR 157.208(d) (2002).

[22] In an effort to encourage pipeline companies to quickly add capacity to meet pressing market needs in the Western United States (particularly California), we adopted several temporary measures. Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 (2001), *further order and reh'g dismissed,* 95 FERC ¶ 61,225 (2001), *order on requests for clarification and reh'g,* 96 FERC ¶ 61,155 (2001). Inter alia, for the period May 14, 2001, through April 30, 2002, we increased the dollar limitations on blanket certificate projects under both the automatic provisions and the prior notice provisions for construction of facilities to deliver additional gas into the western region, expanded the scope of eligible facilities for such projects, and provided, upon request, for shortening of the 45-day prior notice time frame. We propose an analogous approach here, not to encourage additional construction, but to establish authority to be held in reserve, to be called upon to meet a specific need.

[23] Emergency circumstances are extraordinary circumstances, and but for emergencies, we expect companies to proceed, as they have to date, to manage gas flows, system maintenance, and construction on their systems under the current authorities. Because we do not anticipate any need for the Commission to arbitrate what constitutes an emergency, we decline to adopt INGAA's proposal that the Commission declare that an emergency exists in order to trigger exemptions and actions. We believe pipeline companies will be able to identify emergencies conditions on their systems and invoke the proposed expanded blanket authority, as appropriate, without any preliminary determination from the Commission.

on automatic authorization for emergency activities report to the Commission their preparations and plans before breaking ground for reconstruction. Therefore, we propose to amend § 157.207, which provides for an annual retrospective report, listing all blanket projects completed in the prior year. We propose to modify this to require prospective reporting for activities intended to restore service in response to an emergency, with the pipeline company informing the Commission of its intended activities in advance of reconstruction.

32. We propose to include an emergency reporting requirement in § 157.207 by revising the introductory paragraph of that section to read as follows: ''In the case of an emergency due to a sudden unanticipated loss of natural gas supply or capacity, the certificate holder must file, in the manner prescribed in §§ 157.6(a) and 385.2011 of this chapter, a report describing activity to be undertaken to restore service in advance of such activity in accordance with paragraph (i) of this section. In addition, on or before May 1 of each year, the certificate holder must file, in the manner prescribed in §§ 157.6(a) and 385.2011 of this chapter, an annual report of all blanket certificate activities, including all activities undertaken to restore service following a sudden unanticipated loss of natural gas supply or capacity.''

33. We recognize that in filing a report of an intended emergency activity, a company will be unable to supply all the information routinely set forth in a standard annual blanket report. For example, although it will not be possible to provide, before the fact, the § 157.208(e)(3) statement of the ''actual installed cost of each facility item,'' a company planning to proceed under blanket emergency authorization should nevertheless be able to provide projected costs. Thus, a proposed new paragraph (i) of §157.207 would require companies' reports of intended emergency activities to provide to the extent practicable the information required by the regulations cross-referenced by §157.207 for the type of facilities involved. We do not expect this reporting requirement will retard efforts to restore interrupted service, since the report can be prepared coincident with a company's compliance with landowner notification and environmental requirements. Note that the advance report to the Commission is not an application awaiting a Commission response or a prior notice type of proceeding with a requisite waiting period. The report serves only to apprise the Commission of pending activity, and the submission of the description of the intended activity and location constitutes satisfaction of this reporting requirement.

34. We do not view the proposed amendments to our regulations as a significant departure from our past practices. We routinely receive requests for exceptions from full regulatory compliance, and we routinely grant such requests when a company demonstrates good cause therefor. Further, implicit in the NGA section 7 temporary certificate, the section 2.55 replacement and repair regulations, and the part 284 emergency provision, is the presumption that certain categories of equipment failure, human error, and natural disaster require immediate action. The Commission stands willing to grant pipeline companies latitude to construct, reconstruct, and rearrange facilities in an emergency due to a sudden unanticipated loss of gas or capacity that threatens life, health, or property. Finally, we do not expect the proposed amended provisions will be put to use with any regularity, since unlike the standard part 157 regulations, which are employed for routine or relatively minor system modifications, the emergency blanket provisions, by their nature, are only applicable in unexpected and atypical events.

35. Although the Commission can determine that in certain circumstances the public convenience and necessity favor construction and transportation without full adherence to each existing certificate condition, the Commission cannot compromise compliance with statutory or regulatory requirements over which it has no jurisdictional authority. For example, regardless of any circumstances or any Commission finding, the environmental provisions of the National Environmental Policy Act (NEPA) and the safety provisions of DOT must be met. Thus, here, as in our 2001 temporary modification of part 157, ''[w]e emphasize that projects under the expanded blanket authority will remain subject to our existing environmental regulations and compliance provisions''[24] as set forth in § 157.206(d) of our regulations.

36. In an emergency, in addition to the need to identify and resolve environmental and safety issues promptly, easements for a new right-of-way may be needed promptly. If affected landowners agree, it may be possible to obtain the right-of-way without undue delay. Otherwise, even with the right to exercise eminent domain that is available to a pipeline company acting under part 157 blanket certificate authority, securing land rights may extend the duration of the service interruption.

37. Since the Commission lacks the authority to modify certain environmental, safety, and land acquisition procedures, we will, as noted, compile and maintain a list of agencies that hold relevant permitting authorities. (A state's governor, for example, may have the authority to acquire easements expeditiously in the case of a state-declared emergency.) Promptly alerting entities that will be involved in an emergency response should speed the planning, permissions, and reconstruction process.

38. We expect these proposed amendments to part 157 will provide pipeline companies confronting an emergency outage with the flexibility to act on their own initiative, without the delay inherent in the process of applying for case specific authorizations from the Commission. At the same time, the Commission will retain regulatory oversight through the existing blanket certificate procedures sufficient to safeguard the public interest by ensuring pipelines respect landowner property rights and adhere to environmental and safety requirements. Any waiver of the regulatory requirements to restore service in an emergency will be subject to review by the Commission or its delegated agent.

39. Finally, despite the advance report we are proposing in new subparagraph (i) of § 157.207, we are concerned that emergency projects under expanded blanket authority should not proceed without Commission awareness of the details of the project as it goes forward. Accordingly, we will also propose to require any pipeline company that undertakes to replace facilities under the expanded blanket certificate authority proposed herein to consult with Commission staff during the period that the facilities are under construction and we shall require the Director of the Office of Energy Projects (OEP) to designate a staff member to be available to advise and consult on any such project. A staff member designated by the Director of OEP shall be present on the construction site as necessary or appropriate based on the nature of the project and shall have delegated authority to take whatever steps are necessary to insure the protection of all environmental resources during activities associated with construction of the project. This authority shall allow the design and implementation of any additional measures deemed necessary (including stop work authority) to

[24] *Id.,* 95 FERC ¶ 61,225, at 61,776.

assure continued compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from project construction.

Request for Comments

40. The Commission requests that comments on this proposal specifically address whether the proposed expansion of pipeline companies' authority under their part 157 blanket certificates will be sufficient in scope to adequately address situations where immediate action is necessary to restore gas service to prevent loss of life, impairment of health, or damage to property, and to provide for reconstruction of interstate pipeline facilities that have been destroyed or compromised by a sudden, unforeseen natural event or deliberate effort to disrupt the flow of natural gas. Commenters are invited to submit their views and comments on the need for further or broader action by the Commission or Congress.

41. The Commission seeks comment on whether the blanket certificate authorization to construct mainline facilities outside an existing right-of-way should be self-implementing or, rather, subject to a finding by the Commission that an emergency exists and the pipeline's proposed actions are appropriate. Specifically, is INGAA's suggested approach sufficient in scope to address situations where immediate action is necessary to restore gas service lost due to a sudden unanticipated loss of gas or capacity? In the alternative, should there be a short review period in advance of commencing construction to provide the Commission an opportunity to review the actions proposed to be taken by the pipeline? For example, should the regulations provide that unless the Commission does not act to prohibit or modify the pipeline's replacement construction proposal within three days of a pipeline's advance report of intended reconstruction, then the pipeline may commence reconstruction (compare § 284.264(b)(1)(ii) of the regulations)? Lastly, we seek comment on whether the proposed expanded emergency blanket authority should be restricted to include activities undertaken in response to a sudden unanticipated loss of gas or capacity due only to a natural disaster or act of deliberate damage.

Information Collection Statement

42. The Office of Management and Budget (OMB) regulations require that OMB approve certain information collection requirements imposed by agency rule.[25] This proposed rule will not impact information collection. Accordingly, there is no cause to submit this proposed rule to OMB for review under Section 3507(d) of the Paperwork Reduction Act of 1995, 44 U.S.C. 3507(d).

Environmental Analysis

43. The Commission is required to prepare an EA or EIS for any action that may have a significant adverse effect on the human environment.[26] The Commission has categorically excluded certain actions from these requirements as not having a significant effect on the human environment.[27] Section 380.4(a)(21) provides that neither an environmental assessment nor an environmental impact statement will be prepared for the approval of blanket applications pursuant to prior notice filings under §§157.209 through 157.218 of the blanket certificate regulations. The actions proposed herein provide for the emergency reconstruction of previously authorized facilities and thus fall within categorical exclusions in the Commission's regulations for rules that are clarifying, corrective, or procedural, for information gathering, analysis, and dissemination, and for the sale, exchange, and transportation of natural gas that requires no construction of facilities.[28] Therefore, an environmental assessment is unnecessary and has not been prepared in this rulemaking.

Regulatory Flexibility Act Certification

44. The Regulatory Flexibility Act of 1980 (RFA)[29] requires agencies to prepare certain statements, descriptions, and analyses of proposed rules that will have significant economic impact on a substantial number of small entities. Agencies are not required to make such an analysis if a rule would not have such an effect. The Commission does not believe that this proposed rule would have such an effect on small business entities, since the proposed amendments to our regulations would apply only to interstate pipelines, most of which are not small businesses. Accordingly, pursuant to section 605(b) of the RFA, the Commission proposes to certify that the regulations proposed herein will not have a significant adverse impact on a substantial number of small entities.

Comment Procedures

45. The Commission invites interested persons to submit written comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. An original and 14 copies of comments must be filed with the Commission no later than February 27, 2003 and may be filed either in electronic or paper format. Those filing electronically do not need to make a paper filing.

46. Documents filed electronically via the Internet can be prepared in a variety of formats, including WordPerfect, MS Word, Portable Document Format, Rich Text Format, or ASCII format, as listed on FERC's Web site at *http://ferc.gov,* under the eFiling link. The eFiling link provides instructions for how to log in and complete an electronic filing. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgment to the sender's e-mail address upon receipt of comments. User assistance for electronic filing is available at 202–502–8258 or by e-mail to *efiling@ferc.gov.* Comments should not be submitted to the e-mail address.

47. For paper filings, the original and 14 copies of such 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 Nos. RM03–4–000 and AD02–14–000.

48. All comments will be placed in the Commission's public files and will be available for inspection in the Commission's Public Reference Room at 888 First Street, NE., Washington DC 20426, during regular business hours. Additionally, all comments may be viewed, printed, or downloaded remotely via the Internet through FERC's Web site using the Federal Energy Regulatory Records Information System (FERRIS) link.

Document Availability

49. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Web site at *http://www.ferc.gov* and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

50. From FERC's Home Page on the Internet, this information is available in

[25] 5 CFR part 1320 (2002).

[26] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987).

[27] 18 CFR 380.4 (2002).

[28] *See* 18 CFR 380.4(a)(2)(ii), 380.4(a)(5), 380.4(a)(27) (2002).

[29] 5 U.S.C. 601–612.

FERRIS. The full text of this document is available via FERRIS in Portable Document Format (PDF) and WordPerfect format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number excluding the last three digits of this document in the docket number field.

51. User assistance is available for FERRIS and FERC's Web site during normal business hours. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or for TTY contact (202) 502–8659.

List of Subjects in 18 CFR part 157

Administrative practice and procedure, Natural gas, Reporting and record keeping requirements.

By direction of the Commission.

Magalie R. Salas,

Secretary.

In consideration of the foregoing, the Commission proposes to amend part 157, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

1. The authority citation for part 157 continues to read as follows:

Authority: 15 U.S.C. 717–717W, 3301–3432; 42 U.S.C. 7101–7352.

2. In § 157.202, the last sentence in paragraph (b)(2)(i) and paragraph (b)(2)(ii)(C) are revised to read as follows:

§ 157.202 Definitions.

* * * * *

(b) *Subpart F definitions.* * * *

(2)(i) * * * Replacements for the primary purpose of creating additional main line capacity are not eligible facilities; however, replacements for the primary purpose of restoring service to prevent loss of life, impairment of health, or damage to property due to sudden unanticipated damage to main line facilities are eligible facilities.

(ii) *Exclusions:* * * *

(C) A facility, including compression and looping, that alters the capacity of a main line, except replacement facilities covered under § 157.202(b)(2)(i);

* * * * *

3. In § 157.205, paragraph (a), introductory text, is revised to read as follows:

§ 157.205 Notice procedure.

(a) *Applicability.* No activity described in §§ 157.208(b), 157.211(a)(2), 157.214 or 157.216(b), except for activity required to restore service to prevent loss of life, impairment of health, or damage to property in an emergency due to a sudden unanticipated loss of natural gas supply or capacity, is authorized by a blanket certificate granted under this subpart, unless, prior to undertaking such activity:

* * * * *

4. In § 157.207, the introductory text is revised and a new paragraph (i) is added to read as follows:

§ 157.207 General reporting requirements.

In the case of an emergency due to a sudden unanticipated loss of natural gas supply or capacity, the certificate holder must file, in the manner prescribed in §§ 157.6(a) and 385.2011 of this chapter, a report describing activity to be undertaken to restore service in advance of such activity in accordance with paragraph (i) of this section. In addition, on or before May 1 of each year, the certificate holder must file, in the manner prescribed in §§ 157.6(a) and 385.2011 of this chapter, an annual report of all blanket certificate activities, including all activities undertaken to restore service following a sudden unanticipated loss of natural gas supply or capacity. The annual report must be signed under oath by a senior official of the company and list for the previous calendar year:

* * * * *

(i) Reports describing emergency activities to be undertaken to restore service following a sudden unanticipated loss of natural gas supply or capacity shall to the extent practicable contain the information for the facilities as required by the pertinent regulatory provisions specified in paragraphs (a) through (h) of this section. The report shall include the estimated costs of each activity and an updated USGS 7½ minute series (scale 1:24000) topographic map (or map of equivalent or greater detail, as appropriate) showing the location of existing and proposed facilities, and indicating the location of any sensitive environmental areas crossed by either the existing or proposed facilities.

5. In § 157.208, paragraph (a) is revised to read as follows:

§ 157.208 Construction, acquisition, operation, replacement, and miscellaneous rearrangement of facilities.

(a) *Automatic authorization.* If the project cost does not exceed the cost limitations set forth in column 1 of Table I, under paragraph (d) of this section, or if the project is required to restore service to prevent loss of life, impairment of health, or damage to property in an emergency due to a sudden unanticipated loss of natural gas supply or capacity, the certificate holder is authorized to make miscellaneous rearrangements of any facility, or acquire, construct, replace, or operate any eligible facility. For projects undertaken pursuant to this section to restore service to prevent loss of life, impairment of health, or damage to property due to a sudden unanticipated loss of natural gas supply or capacity, the Director of the Office of Energy Projects shall designate a staff member to advise and consult with the certificate holder, and the certificate holder shall consult with the designated staff member during the period that the construction is in progress. A staff member designated by the Director of the Office of Energy Projects shall be present on the construction site as necessary or appropriate based on the nature of the project and shall have delegated authority to take whatever steps are necessary to insure the protection of all environmental resources during activities associated with construction of the project. This authority shall allow the design and implementation of any additional measures deemed necessary (including stop work authority) to assure continued compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from project construction.

* * * * *

[FR Doc. 03–1698 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

21 CFR Part 1308

[DEA–238N]

Schedules of Controlled Substances: Temporary Placement of Alpha-methyltryptamine and 5-methoxy-N,N-diisopropyltryptamine Into Schedule I

AGENCY: Drug Enforcement Administration (DEA), Justice.

ACTION: Notice of intent.

SUMMARY: The Deputy Administrator of the Drug Enforcement Administration (DEA) is issuing this notice of intent to temporarily place alpha-methyltryptamine (AMT) and 5-

methoxy-N,N-diisopropyltryptamine (5-MeO-DIPT) into Schedule I of the Controlled Substances Act (CSA) pursuant to the temporary scheduling provisions of the CSA. This intended action is based on a finding by the DEA Deputy Administrator that the placement of AMT and 5-MeO-DIPT into Schedule I of the CSA is necessary to avoid an imminent hazard to the public safety. Finalization of this action will impose the criminal sanctions and regulatory controls of a Schedule I substance on the manufacture, distribution, and possession of AMT and 5-MeO-DIPT.

FOR FURTHER INFORMATION CONTACT:

Frank Sapienza, Chief, Drug and Chemical Evaluation Section, Office of Diversion Control, Drug Enforcement Administration, Washington, DC 20537, Telephone (202) 307–7183.

SUPPLEMENTARY INFORMATION:

Background

The Comprehensive Crime Control Act of 1984 (Pub. L. 98–473) amended section 201 of the CSA (21 U.S.C. 811) to give the Attorney General the authority to temporarily place a substance into Schedule I of the CSA for one year without regard to the requirements of 21 U.S.C. 811(b) if he finds that such action is necessary to avoid an imminent hazard to the public safety. The Attorney General may extend the temporary scheduling up to 6 months. A substance may be temporarily scheduled under the emergency provision of the CSA if that substance is not listed in any other schedule under section 202 of the CSA (21 U.S.C. 812) or if there is no exemption or approval in effect under 21 U.S.C. 355 for the substance. The Attorney General has delegated his authority under 21 U.S.C. 811 to the Deputy Administrator of DEA (28 CFR 0.100).

Section 201(h)(4) of the CSA (21 U.S.C. 811(h)(4)) requires the Deputy Administrator to notify the Assistant Secretary for Health, delegate of the Secretary of Health and Human Services, of his intention to temporarily place a substance into Schedule I of the CSA. Comments submitted by the Assistant Secretary for Health in response to this notification, including whether there is an exemption or approval in effect for the substance in question under the Federal Food, Drug and Cosmetic Act, shall be taken into consideration before a final order is published.

In making a finding that places a substance temporarily into Schedule I of the CSA is necessary to avoid an imminent hazard to the public safety, the Deputy Administrator is required to consider three of the eight factors set forth in section 201(c) of the CSA (21 U.S.C. 811(c)). These factors are as follows: (4) History and current pattern of abuse; (5) The scope, duration and significance of abuse; and (6) What, if any, risk there is to the public health.

Alpha-methyltryptamine and 5-methoxy-N,N-diisopropyltryptamine

Alpha-methyltryptamine (AMT) and 5-methoxy-N,N-diisopropyltryptamine (5-MeO-DIPT) are tryptamine (indoleethylamine) derivatives and share several similarities with the Schedule I tryptamine hallucinogens, alpha-ethyltryptamine (AET) and N,N-dimethyltryptamine (DMT), respectively. Several other tryptamines also produce hallucinogenic/stimulant effects and are controlled as Schedule I substances under the CSA (bufotenine, diethyltryptamine, psilocybin and psilocin). Although tryptamine itself appears to lack consistent hallucinogenic/stimulant effects, substitutions on the indole ring and the ethylamine side-chain of this molecule result in pharmacologically active substances (McKenna and Towers, J. Psychoactive Drugs, 16: 347–358, 1984).

The chemical structures of AMT and 5-MeO-DIPT possess the critical features necessary for hallucinogenic/stimulant activity. Thus, both AMT and 5-MeO-DIPT are likely to have a pharmacological profile substantially similar to other Schedule I tryptamine derivatives such as DMT and AET. In drug discrimination studies, both AMT and 5-MeO-DIPT substitute for 1-(2,5-dimethoxy-4-methylphenyl)-aminopropane (DOM), a phenethylamine-based hallucinogen in Schedule I of the CSA. The potencies of DOM-like discriminative stimulus effects of these and several other similar tryptamine derivatives correlate well with their hallucinogenic potencies in humans (Glennon *et al.,* Eur. J. Pharmacol. 86:453–459, 1983).

AMT shares other pharmacological properties with Schedule I hallucinogens such as AET. AMT increases systolic and diastolic arterial blood pressures. The behavioral effects of orally administered AMT (20 mg) in humans are slow in onset, occurring after 3 to 4 hours and gradually subside after 12 to 24 hours, but may last up to 2 days in some subjects. The majority of the subjects report nervous tension, irritability, restlessness, inability to sleep, blurry vision, mydriasis and equate the effects of a 20 mg dose to those of 50 micrograms of lysergic acid diethylamide (LSD) (Hollister *et al.,* J. Nervous Ment. Dis., 131: 428–434, 1960; Murphree *et al.,* Clin. Pharmacol. Ther., 2: 722–726, 1961). AMT also produces hallucinations and dextroamphetamine-like mood elevating effects.

5-MeO-DIPT also produces pharmacological effects similar to those of other Schedule I hallucinogens such as DMT. The synthesis and preliminary human psychopharmacology study on 5-MeO-DIPT was first published in 1981 (Shulgin and Carter, Comm. Psychopharmacol. 4: 363–369, 1981). 5-MeO-DIPT is an orally active hallucinogen. Following oral administration of 6–10 mg, 5-MeO-DIPT produces subjective effects with an onset at about 20–30 minutes, a peak at about 1–1.5 hours and a duration of about 3–6 hours. Subjects who have been administered 5-MeO-DIPT are talkative and disinhibited. 5-MeO-DIPT causes mydriasis. High doses of 5-MeO-DIPT produce nausea, jaw clenching, muscle tension and overt hallucinations with both auditory and visual distortions.

History and Current Pattern of Abuse

The popularity and use of hallucinogenic/stimulant substances at raves (all-night dance parties) and other social venues have been a major problem in Europe since the 1990s. In the past several years, this activity has spread to the United States. The Schedule I controlled substance 3,4-methylenedioxymethamphetamine (MDMA or Ecstasy) and its analogues are the most frequently abused drugs at these raves. Their abuse has been associated with both acute and long-term public health and safety problems. Raves have also become venues for the trafficking and abuse of new, non-controlled substances distributed as legal substitutes for, or in addition to, MDMA. 5-MeO-DIPT and AMT belong to such a group of substances.

Data gathered from published studies, supplemented by reports on Internet websites indicate that these are often administered orally at doses ranging from 15–40 mg for AMT and 6–20 mg for 5-MeO-DIPT. Other routes of administration include smoking and snorting. Data from law-enforcement officials indicate that 5-MeO-DIPT is often sold as ''Foxy'' or ''Foxy Methoxy'', while AMT has been sold as ''Spirals'' at least in one case. Both substances have been commonly encountered in tablet and capsule forms.

Scope, Duration and Significance of Abuse

According to forensic laboratory data, the first encounter of AMT and 5–MeO–

DIPT occurred in 1999. Since then, law enforcement officials in Arizona, California, Colorado, Delaware, Florida, Idaho, Illinois, Iowa, New Jersey, Oregon, Texas, Virginia, Washington, Wisconsin and the District or Columbia have encountered these substances. According to the Florida Department of Law Enforcement (FDLE), the abuse by teens and young adults of AMT and 5–MeO–DIPT is an emerging problem. There have been reports of abuse of AMT and 5–MeO–DIPT at clubs and raves in Arizona, California, Florida and New York. Many tryptamine-based substances are illicitly available from United States and foreign chemical companies and from individuals through the Internet. A gram of AMT or 5–MeO–DIPT as bulk powder costs less than $150 from illicit sources on the Internet. DEA is not aware of any legitimate medical or scientific use of AMT and 5–MeO–DIPT. There is recent evidence suggesting the attempted clandestine production of AMT and 5–MeO–DIPT in Nevada, Virginia and Washington, DC.

Public Health Risks

AMT and 5–MeO–DIPT share substantial chemical and pharmacological similarities with other Schedule I tryptamine-based hallucinogens in Schedule I of the CSA (AET and DMT). This makes it likely that these drugs cause similar health hazards. Tryptamine, the parent molecule of AMT and 5–MeO–DIPT, is known to produce convulsions and death in animals (Tedeschi *et al.*, J. Pharmacol. Exp. Ther. 126:223–232, 1959). AMT and 5–MeO–DIPT, similar to other tryptaine- or phenethylamine-based hallucinogens, through the alteration of sensory perception and judgment can pose serious health risks to the user and the general public. Further, there have been several self-reports on Internet websites describing the reported abuse of these substances in combination with other controlled drugs, namely MDMA, marijuana, gamma hydroxybutyric acid (GHB) and 2,5-dimethoxy-4-(n)-propylthiophenethylamine (2C–T–7). This practice of drug abuse involving combinations poses additional health risks to the users and the general public. Available information indicates that AMT and 5–MeO–DIPT lack any approved therapeutic use in the United States. The safety of these substances for use in humans has not been studied.

DEA has considered the three criteria for placing a substance into Schedule I of the CSA (21 U.S.C. 812). The data available and reviewed for AMT and 5–MeO–DIPT indicate that these substances each have a high potential for abuse, no currently accepted medical use in treatment in the United States and are not safe for use under medical supervision.

Role of the Assistant Secretary for Health in Temporary Scheduling

Section 201(h)(4) of the CSA (21 U.S.C. 811(h)(4)) requires the Deputy Administrator to notify the Assistant Secretary for Health, delegate of the Secretary of Health and Human Services, of his intention to temporarily place substances into Schedule I of the CSA. Comments submitted by the Assistant Secretary for Health in response to the notification regarding AMT and 5–MeO–DIPT, including whether there is an exemption or approval in effect for the substances in question under the Federal Food, Drug and Cosmetic Act, shall be taken into consideration before a final order is published.

Based on the above data, the continued uncontrolled distribution and abuse of AMT and 5–MeO–DIPT pose an imminent risk to the public safety. DEA is not aware of any recognized therapeutic uses of these substances in the United States.

In accordance with the provisions of section 201(h) of the CSA (21 U.S.C. 811(h)) and 28 CFR 0.100, the Deputy Administrator has considered the available data and the three factors required for a determination to temporarily schedule AMT and 5–MeO–DIPT in Schedule I of the CSA and finds that placement of AMT and 5–MeO–DIPT into Schedule I of the CSA is necessary to avoid an imminent hazard to the public safety.

Because the Deputy Administrator finds that it is necessary to temporarily place AMT and 5–MeO–DIPT into Schedule I to avoid an imminent hazard to the public safety, the final order, if issued, will be effective on the date of publication of the **Federal Register**. AMT and 5–MeO–DIPT will be subject to the regulatory controls and administrative, civil and criminal sanctions applicable to the manufacture, distribution, possession, importing and exporting of a Schedule I controlled substance under the CSA. Further, it is the intention of the Deputy Administrator to issue such a final order as soon as possible after the expiration of thirty days from the date of publication of this notice and the date that notification was transmitted to the Assistant Secretary for Health.

Regulatory Certifications

Regulatory Flexibility Act

The Deputy Administrator hereby certifies that this rulemaking has been drafted in accordance with the Regulatory Flexibility Act (5 U.S.C. 605(b)), has reviewed this regulation, and by approving it certifies that this regulation will not have a significant economic impact on a substantial number of small entities. This action provides a notice of intent to temporarily place AMT and 5-MeO-DIPT into Schedule I of the CSA. DEA is not aware of any legitimate uses of AMT and 5-MeO-DIPT in the United States.

Executive Order 12988

This regulation meets the applicable standards set forth in Sections 3(a) and 3(b)(2) of Executive Order 12988 Civil Justice Reform.

Executive Order 13132 Federalism

This rule 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 13132, it is determined that this rule will not has sufficient federalism implications to warrant the preparation of a Federalism Assessment.

Unfunded Mandates Reform Act

This rule will not result in the expenditure by State, local and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more in any one year, and it will not significantly or uniquely affect small governments. Therefore, no actions were deemed necessary under provisions of the Unfunded Mandates Reform Act of 1995.

Small Business Regulatory Enforcement Fairness Act of 1996

This rule is not a major rule as defined by section 804 of the Small Business Regulatory Enforcement Fairness Act of 1996. This rule will not result in an annual effect on the economy of $100,000,000 or more; a major increase in costs or prices; or significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based companies to compete with foreign-based companies in domestic and export markets.

List of Subjects in 21 CFR Part 1308

Administrative practice and procedure, Drug traffic control, Narcotics, Prescription drugs, Reporting and record keeping requirements.

Under the authority vested in the Attorney General by Section 201(h) of the CSA (21 U.S.C. 811(h), and delegated to the Deputy Administrator of the DEA by Department of Justice regulations (28 CFR 0.100), the Deputy Administrator hereby intends to order that 21 CFR part 1308 be amended as follows:

PART 1308—SCHEDULES OF CONTROLLED SUBSTANCES

1. The authority citation for 21 CFR part 1308 continues to read as follows:

Authority: 21 U.S.C. 811, 812, 871b, unless otherwise noted.

2. Section 1308.11 is to be amended by adding paragraph (g)(6) and (7) to read as follows:

§ 1308.11 Schedule I.

* * * * *

(g) * * *

(6) Alpha-methyltryptamine (AMT), its isomers, salts and salts of isomers: 7432.

(7) 5-methoxy-N,N-diisopropyltryptamine (5-MeO-DIPT), its isomers, salts and salts of isomers: 7439.

* * * * *

Dated: January 10, 2003.

John B. Brown, III,

Deputy Administrator.

[FR Doc. 03–1800 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–09–M

DEPARTMENT OF TRANSPORTATION

Coast Guard

33 CFR Part 110

[CGD08–02–018]

RIN 2115–AA98

Anchorage Regulation; Bolivar Roads, Galveston, TX

AGENCY: Coast Guard, DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to create a new anchorage area in Bolivar Roads near Galveston, Texas. The establishment of this new anchorage area would enhance navigational safety, support regional maritime security needs, and contribute to the free flow of commerce in the Houston/Galveston area.

DATES: Comments and related material must reach the Coast Guard on or before March 31, 2003.

ADDRESSES: You may mail comments and related material to Commander, Eighth Coast Guard District (m), Hale Boggs Federal Bldg., 501 Magazine Street, New Orleans, LA 70130, or deliver comments and related material to Room 1341 at the same address between 8 a.m. and 3:30 p.m., Monday through Friday, except Federal holidays. Commander, Eighth Coast Guard District (m) maintains the public docket for this rulemaking. Comments and material received from the public, as well as documents indicated in this preamble as being available in the docket, will become part of this docket and will be available for inspection or copying at Commander, Eighth Coast Guard District (m) between 8 a.m. and 3:30 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Lieutenant (LT) Karrie Trebbe, Project Manager for Eighth Coast Guard District Commander, telephone (504) 589–6271.

SUPPLEMENTARY INFORMATION:

Request for Comments

We encourage you to participate in this rulemaking by submitting comments and related material. If you do so, please include your name and address, identify the docket number for this rulemaking (CCGD8–02–018), indicate the specific section of this document to which each comment applies, and give the reason for each comment. Please submit all comments and related material in an unbound format, no larger than 8½ by 11 inches, suitable for copying. If you would like to know they reached us, please enclose a stamped, self-addressed postcard or envelope. We will consider all comments and material received during the comment period. We may change this proposed rule in view of them.

Public Meeting

We do not now plan to hold a public meeting. But you may submit a request for a meeting by writing to Commander, Eighth Coast Guard District (m) at the address under **ADDRESSES** explaining why one would be beneficial. If we determine that a public meeting would aid this rulemaking, we will hold one at a time and place announced by a later notice in the **Federal Register**.

Background and Purpose

At its February 2002 meeting the Houston/Galveston Navigation Safety Advisory Committee (HOGANSAC) recommended establishment of a third anchorage area in the Galveston Bay area. HOGANSAC, a Congressionally-chartered Federal advisory committee, is responsible for advising, consulting with and making recommendations to the Secretary of Transportation on matters relating to the transit of vessels to and from the ports of Galveston, Houston and Texas City and the safety of maritime navigation in the Galveston Bay area. Participants at the February 2002 HOGANSAC meeting noted that a third anchorage in the Bolivar Roads area was necessary to address port security and navigation safety concerns. After extensive discussion, including the observations of and comments from members of the public in attendance, HOGANSAC recommended that the Coast Guard establish a third anchorage area in Bolivar Roads.

Based on the recommendation of HOGANSAC the Coast Guard proposes a third anchorage area, anchorage area (C), in Bolivar Roads. The proposed anchorage area, located inside the Galveston Bay Entrance Jetties, would provide a sheltered location for vessels to anchor during heavy weather or reduced visibility conditions. The existing anchorages, anchorage area (A) and anchorage area (B), are generally full during these same periods and there is no alternative sheltered anchorage in Bolivar Roads. The proposed location of anchorage area (C), abuts the western edge of anchorage area (B), is in a naturally deep portion of Bolivar Roads, and is outside any heavily traveled section of the waterway.

This third anchorage area is also necessary because port security-related initiatives adopted by various terminals and facilities in the Galveston Bay area have restricted pier side operations critical to the efficient flow of maritime commerce. For example, bunkering, provisions deliveries, and personnel transfer operations are restricted or prohibited by numerous facilities in the ports of Galveston, Houston and Texas City. The nature of those activities requires that they be accomplished in calm water conditions and relatively close to shore. As a result, vessel operators and ship owners rely upon the existing anchorage areas (anchorage areas (A) and (B)) in Galveston Bay to conduct these operations. Increasingly, anchorage space in those areas is in high demand. A third designated anchorage area would relieve congestion and provide anchorage space to accommodate the ever-increasing volumes of traffic in the Galveston Bay area.

Discussion of Proposed Rule

The proposed amendment would create a new anchorage area, to be known as anchorage area (C), bounded by rhumb lines joining points at:

Latitude	Longitude
29°20′39.0″ N.	94°46′07.5″ W.
29°21′06.1″ N.	94°47′00.2″ W.
29°21′24.0″ N.	94°46′34.0″ W.
29°21′14.5″ N.	94°45′49.0″ W.

The anchorage area would be for the temporary use by vessels of all types. Vessels may occupy the anchorage area during a wide range of conditions and for a broad variety of purposes. For example, vessels would be allowed to anchor temporarily while taking on stores, transferring personnel, or engaging in bunkering or lightering operations. Vessels would also be allowed to use the anchorage area while awaiting weather and other conditions favorable to resuming their voyage. Except when stress of weather makes sailing impractical or hazardous, vessels would not be allowed to anchor in anchorage area (C) for more than 48 hours unless authorized by the Captain of the Port Houston-Galveston. Authorization to remain for more than 48 hours would be obtained via VHF–FM radio through Coast Guard Vessel Traffic Service Houston/Galveston. No vessel with a draft of less than 16 feet would be allowed to occupy anchorage area (C) without prior approval of the Captain of the Port Houston-Galveston. Vessels would not be allowed to anchor so as to obstruct the passage of other vessels proceeding to and from other anchorage spaces. Anchors would not be placed in the channel and no portion of the hull or rigging of any anchored vessel would be allowed to extend outside the limits of the anchorage area. Vessels using spuds for anchors would have to anchor as close to shore as practicable. Fixed moorings, piles or stake and floats, and buoys for marking anchorages or moorings in place would be prohibited. Whenever the maritime or commercial interests of the United States so require, the Captain of the Port Houston-Galveston or his designated representative may direct the movement of any vessel anchored or moored within the anchorage areas.

Regulatory Evaluation

This proposed rule is not a ''significant regulatory action'' under section 3(f) of Executive Order 12866, Regulatory Planning and Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order. It is not ''significant'' under the regulatory policies and procedures of the Department of Transportation (DOT) (44 FR 11040, February 26, l979).

We expect the economic impact of this proposed rule to be so minimal that a full Regulatory Evaluation under paragraph 10 (e) of the regulatory policies and procedures of DOT is unnecessary. The proposed anchorage area would not unnecessarily restrict traffic as it is located outside of the established navigation channel. Vessels would be able to maneuver in, around and through the anchorage. Operators who choose to maneuver their vessels around the limits of the proposed anchorage area would not be significantly impacted because the total route deviation to cross from one side of the anchorage to the other following the perimeter of the anchorage is only 1.4 nautical miles.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this proposed rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this proposed rule would not have a significant economic impact on a substantial number of small entities. This proposed rule could potentially affect the following entities, some of which might be small entities: the owners or operators of vessels intending to fish or anchor in, or transit through, the proposed anchorage area (C) in Bolivar Roads.

The number of small entities impacted and the extent of the impact, if any, is expected to be minimal. The proposed anchorage would be located in an area of Bolivar Roads that is not a popular or productive fishing location. Further, the proposed location is in an area not routinely transited by vessels heading to, or returning from, known fishing grounds. Finally, the anchorage would be located in an area that is not currently used by small entities, including small vessels, for anchoring due to the depth of water naturally present in the area.

If you think that your business, organization, or governmental jurisdiction qualifies as a small entity and that this rule would have a significant economic impact on it, please submit a comment (see **ADDRESSES**) explaining why you think it qualifies and how and to what degree this rule would economically affect it.

Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this proposed rule so that they can better evaluate its effects on them and participate in the rulemaking. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact LT Karrie Trebbe, Project Manager for Eighth Coast Guard District Commander, at (504) 589–6271.

Collection of Information

This proposed rule would call for no new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. We have analyzed this proposed rule under that Order and have determined that it does not have implications for federalism.

Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 or more in any one year. Though this proposed rule would not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This proposed rule would not affect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Civil Justice Reform

This proposed rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice

Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

Protection of Children

We have analyzed this proposed rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and would not create an environmental risk to health or risk to safety that might disproportionately affect children.

Indian Tribal Governments

This proposed rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it would not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

To help the Coast Guard establish regular and meaningful consultation and collaboration with Indian and Alaskan Native tribes, we published a notice in the **Federal Register** (66 FR 36361, July 11, 2001) requesting comments on to best carry out the order. We invite your comments on how this proposed rule might impact tribal governments, even if that impact may not constitute a ''tribal implication'' under the Order.

Energy Effects

We have analyzed this proposed rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that Order because it is not a ''significant regulatory action'' under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. It has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action. Therefore, it does not require a Statement of Energy Effects under Executive Order 13211.

Environment

We have considered the environmental impact of this proposed rule and concluded that, under figure 2–1, paragraph (34)(f), of Commandant Instruction M16475.lD, this rule is categorically excluded from further environmental documentation because it is a regulation establishing an additional anchorage ground. A ''Categorical Exclusion Determination'' is available in the docket where indicated under **ADDRESSES.**

List of Subjects in 33 CFR Part 110

Anchorage grounds.

For the reasons discussed in the preamble, the Coast Guard proposes to amend 33 CFR part 110 as follows:

PART 110—ANCHORAGE REGULATIONS

1. The authority citation for part 110 continues to read as follows:

Authority: 33 U.S.C. 471, 1221 through 1236, 2030, 2035, 2071; 49 CFR 1.46 and 33 CFR 1.05–1(g).

2. In § 110.197, add a new paragraph (a)(3), and revise paragraph (b) to read as follows:

§ 110.197 Galveston Harbor, Bolivar Roads Channel, Texas.

(a) * * *

(3) Anchorage area (C). The water bounded by a line connecting the following points:

Latitude	Longitude
29°20′39.0″ N	94°46′07.5″ W
29°21′06.1″ N	94°47′00.2″ W
29°21′14.5″ N	94°46′34.0″ W
29°21′24.0″ N	94°45′49.0″ W

and thence to the point of beginning.

(b) *The regulations.* (1) The anchorage area is for the temporary use of vessels of all types, but especially for naval and merchant vessels awaiting weather and other conditions favorable to the resumption of their voyages.

(2) Except when stress of weather makes sailing impractical or hazardous, vessels shall not anchor in anchorage areas (A) or (C) for more than 48 hours unless expressly authorized by the Captain of the Port Houston-Galveston. Permission to anchor for longer periods may be obtained through Coast Guard Vessel Traffic Service Houston/Galveston on VHF–FM channels 12 (156.60 MHz) or 13 (156.65 MHz).

(3) No vessel with a draft of less than 22 feet may occupy anchorage (A) without prior approval of the Captain of the Port.

(4) No vessel with a draft of less than 16 feet may anchor in anchorage (C) without prior approval of the Captain of the Port Houston-Galveston.

(5) Vessels shall not anchor so as to obstruct the passage of other vessels proceeding to or from other anchorage spaces.

(6) Anchors shall not be placed in the channel and no portion of the hull or rigging of any anchored vessel shall extend outside the limits of the anchorage area.

(7) Vessels using spuds for anchors shall anchor as close to shore as practicable, having due regard for the provisions in paragraph (b)(5) of this section.

(8) Fixed moorings, piles or stakes, and floats or buoys for marking anchorages or moorings in place, are prohibited.

(9) Whenever the maritime or commercial interests of the United States so require, the Captain of the Port, or his authorized representative, may direct the movement of any vessel anchored or moored within the anchorage areas.

Dated: January 3, 2003.

Roy J. Casto,

Rear Admiral, U.S. Coast Guard, Commander, Eighth Coast Guard District.

[FR Doc. 03–1873 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF VETERANS AFFAIRS

38 CFR Part 3

RIN 2900–AL37

Effective Dates of Benefits for Disability or Death Caused by Herbicide Exposure; Disposition of Unpaid Benefits After Death of Beneficiary

AGENCY: Department of Veterans Affairs.

ACTION: Proposed rule.

SUMMARY: The Department of Veterans Affairs (VA) proposes to amend its adjudication regulations concerning certain awards of disability compensation and dependency and indemnity compensation (DIC). Under the proposed amendment, certain awards of disability compensation or DIC made pursuant to liberalizing regulations concerning diseases presumptively associated with herbicide exposure may be made effective retroactive to the date of the claim or the date of a previously denied claim, even if such date is earlier than the effective date of the regulation establishing the presumption. The proposed rule also provides that VA may pay to certain individuals any amounts a deceased beneficiary was entitled to receive under the effective-date provisions of this proposed rule, but which were not paid prior to the beneficiary's death. This amendment appears necessary to reflect the requirements of court orders in a class-action case.

DATES: Comments must be received on or before March 31, 2003.

ADDRESSES: Mail or hand deliver written comments to: Director, Office of Regulatory Law (02D), Room 1154, 810 Vermont Ave., NW., Washington, DC 20420; or fax comments to (202) 273–9289; or e-mail comments to *OGCRegulations@mail.va.gov.* Comments should indicate that they are submitted in response to ''RIN 2900–AL37.'' All comments received will be available for public inspection in the Office of Regulatory Law, Room 1158, between the hours of 8 a.m. and 4:30 p.m., Monday through Friday (except holidays).

FOR FURTHER INFORMATION CONTACT: David Barrans, Staff Attorney (022), Office of General Counsel, Department of Veterans Affairs, 810 Vermont Avenue, NW., Washington, DC 20420, (202) 273–6332.

SUPPLEMENTARY INFORMATION: A series of court orders in the class-action litigation in *Nehmer* v. *United States Department of Veterans Affairs,* No. CV–86–6160 TEH (N.D. Cal.), requires VA to assign retroactive effective dates for certain awards of disability compensation and DIC in a manner not provided for in any existing statute or regulation. The court orders require that, when VA awards disability compensation or DIC pursuant to a regulatory presumption of service connection under the Agent Orange Act of 1991, Pub. L. 102–4, VA must in certain cases make the award effective retroactive to the date of the claimant's application or the date of a previously-denied application, even if such date is earlier than the effective date of the regulation establishing the presumption. Current regulations, however, prohibit VA from making a benefit award effective any earlier than the effective date of the regulation establishing the presumption. Because the conflict between current statutes and regulations and the *Nehmer* court orders may create confusion, we propose to amend our regulations to reflect the requirements of the *Nehmer* court orders.

In 1991, Congress enacted the Agent Orange Act of 1991, Pub. L. 102–4 (codified at 38 U.S.C. 1116 and in the notes to that section). That Act established presumptions for chloracne, non-Hodgkins lymphoma, and soft-tissue sarcoma. It further provided that VA would obtain reports from the National Academy of Sciences (NAS) every two years for a ten-year period, assessing the available scientific evidence regarding the association between exposure to herbicides and the development of diseases in humans. After receiving each report, VA must determine whether there is a ''positive association'' between herbicide exposure and any of the diseases discussed in the report. If a positive association exists for any such disease, VA must issue regulations to establish a presumption of service connection for that disease in veterans exposed to herbicides during service. VA has established presumptions of service connection for seven additional diseases or categories of disease, which are listed in 38 CFR 3.309(e).

The Agent Orange Act of 1991 provides that regulations issued pursuant to that act shall take effect on the date they are issued. Under generally applicable effective-date rules in 38 U.S.C. 5110(g) and 38 CFR 3.114, when VA awards benefits pursuant to a liberalizing regulation, the award may not be made effective any earlier than the effective date of the liberalizing regulation. Under those provisions, awards based on presumptions of service connection established under the Agent Orange Act of 1991 can be made effective no earlier than the date VA issued the regulation authorizing the presumption.

However, the district court orders in the *Nehmer* litigation create an exception to the generally applicable rules in 38 U.S.C. 5110(g) and 38 CFR 3.114, and require VA to assign retroactive effective dates for certain awards of disability compensation and DIC that are based on VA's regulations under the Agent Orange Act of 1991, Pub. L. 102–4. This exception applies only to claims by members of the *Nehmer* class. VA is required to comply with the district court's orders, which have been affirmed by the United States Court of Appeals for the Ninth Circuit to the extent they were appealed. Accordingly, we propose to issue a regulation explaining the requirements established by those orders to ensure timely and consistent adjudication under those orders without further need for special instructions.

The *Nehmer* court orders also require that, if an individual was entitled to retroactive benefits as a result of the court orders but died prior to receiving such payment, VA must pay the entire amount of such retroactive payments to the veteran's estate, without regard to statutory limits on payment of benefits following a beneficiary's death. Section 5121(a) of title 38, United States Code, provides that, when VA benefits remain due and unpaid at the time of a beneficiary's death, VA may pay to certain survivors only the portion of such benefits that accrued during the two-year period preceding death. Current VA regulations reflect the requirements of section 5121(a), and contain no exception for cases covered by the *Nehmer* court orders. Because the conflict between current regulations and the *Nehmer* court orders may create confusion, we propose to amend our regulations to reflect the requirements of the *Nehmer* court orders. Accordingly, we propose to issue rules reflecting the limited exception to section 5121(a) established by the *Nehmer* court orders. This exception applies only to certain benefits for members of the *Nehmer* class. As stated above, the intent of this rule is to ensure timely and consistent compliance with the court's orders without the need for further special instructions.

The Nehmer Litigation

The *Nehmer* litigation was initiated in 1986 to challenge a VA regulation, former 38 CFR 3.311a (which has since been rescinded) that stated, among other things, that chloracne was the only disease shown by sound medical and scientific evidence to be associated with herbicide exposure. In 1987, the district court certified the case as a class action on behalf of all Vietnam veterans and their survivors who had been denied VA benefits for a condition allegedly associated with herbicide exposure or who would be eligible to file a claim for such benefits in the future. In an order issued on May 3, 1989, the court invalidated the portion of the regulation providing that no condition other than chloracne was associated with herbicide exposure and voided all VA decisions denying benefit claims under that portion of the regulation. *Nehmer* v. *United States Veterans' Admin.,* 712 F. Supp. 1404 (N.D. Cal. 1989).

After Congress enacted the Agent Orange Act of 1991, Pub. L. 102–4, VA and the plaintiff class in *Nehmer* entered into a stipulation to address remedial issues resulting from the May 1989 order. The stipulation provided that VA would not deny any claims of the *Nehmer* class members until VA had acted on the first NAS report issued under the Agent Orange Act of 1991, Pub. L. 102–4. The stipulation further stated that, once VA issued regulations establishing a presumption of service connection for any disease pursuant to the Act, VA would readjudicate all claims for any such disease in which a prior denial had been voided by the district court's May 3, 1989 order and would adjudicate all similar claims filed after May 3, 1989. The stipulation stated that, if benefits were granted upon readjudication of a claim where a prior denial was voided, the effective date of the benefit award would be the date VA received the claim underlying the

voided decision or the date the disability arose or the death occurred, whichever was later. In claims filed after May 3, 1989, the stipulation stated that the effective date of any benefits awarded would be the date VA received the claim or the date the disability arose or the death occurred, whichever was later. The district court incorporated the stipulation in a final order.

On October 15, 1991, VA issued a regulation establishing a presumption of service connection for soft-tissue sarcomas based on herbicide exposure. On February 6, 1991, the Agent Orange Act of 1991, Pub. L. 102–4, established statutory presumptions of service connection for non-Hodgkin's lymphoma, soft-tissue sarcomas, and chloracne. In June 1993, VA received the first NAS report under the Agent Orange Act of 1991. Thereafter, VA issued regulations establishing presumptions of service connection for four additional diseases (Hodgkin's disease, February 3, 1994; porphyria cutanea tarda, February 3, 1994; respiratory cancers, June 9, 1994; multiple myeloma, June 9, 1994). In 1994, VA began to readjudicate the claims where a prior denial had been voided by the 1989 court order and to adjudicate claims filed subsequent to that order. In cases where VA granted benefits upon such readjudication or adjudication, it assigned effective dates as required by the *Nehmer* stipulation and order, even though the effective dates in many cases were earlier than the effective dates of the statute or liberalizing regulations that authorized the awards.

In 1996, VA received the second NAS report under the Agent Orange Act of 1991. Based on new information contained in that report, VA issued regulations on November 7, 1996 establishing presumptions of service connection for prostate cancer and acute and subacute peripheral neuropathy. In 2001, based on new information in a later NAS report, VA established a presumption of service connection for type 2 diabetes effective July 9, 2001.

In 2000, the parties to the *Nehmer* case disagreed as to whether the retroactive-payment provisions of the *Nehmer* stipulation and order applied to all eight diseases that were associated with herbicide exposure at that time (type 2 diabetes had not yet been recognized) or only to the seven diseases that were presumptively service connected based on the Agent Orange Act of 1991, Pub. L. 102–4, and the first NAS report under that statute. The plaintiffs argued that the stipulation required VA to pay retroactive benefits for all diseases that are service connected at any time under the Agent Orange Act of 1991, Pub. L. 102–4. VA argued that the stipulation required retroactive payment only for disease service connected based on the first NAS report, and that the broader interpretation urged by the plaintiffs was contrary to the Agent Orange Act of 1991, Pub. L. 102–4 and 38 U.S.C. 5110(g).

In a December 12, 2000 order, the district court held that the stipulation and order required VA to give retroactive effect to all regulations issued under the Agent Orange Act of 1991, Pub. L. 102–4. VA appealed that order to the United States Court of Appeals for the Ninth Circuit. On April 1, 2002, the Court of Appeals affirmed the district court's order.

Purpose of This Rule

We propose to issue a new regulation, to be codified at 38 CFR 3.816, to explain the rules VA is required to apply as a result of the court orders in the *Nehmer* case. Those rules are complex and are not reflected in any current statute or regulation. Moreover, the public may have difficulty accessing and understanding the court orders establishing those rules. Accordingly, we believe a regulation explaining the *Nehmer* rules is necessary to provide guidance to VA personnel as well as to VA claimants and their representatives.

To the extent the rules required by the *Nehmer* court orders depart from the generally-applicable rules in 38 U.S.C. 5110(g) and 5121(a), they are judicially-created exceptions to those general rules. VA is required to comply with the *Nehmer* court orders. In order to clarify the basis for this regulation, we propose to state, in § 3.816(a), that these rules are required by the *Nehmer* court orders.

Definitions

The effective-date rules required by the *Nehmer* court orders apply only to members of the plaintiff class certified by the district court in that case. In a 1987 order, the district court ruled that the *Nehmer* class would consist of all veterans and their survivors who have applied for VA benefits for disability or death due to exposure in service to an herbicide containing dioxin or who would become eligible in the future to apply for such benefits. Accordingly, any Vietnam veteran would potentially be a *Nehmer* class member, as would any survivors of such veteran who would be eligible to apply for DIC. The effective-date provisions of this rule would apply only to class members entitled to disability compensation or DIC for disability or death due to a disease associated with herbicide exposure. Accordingly, for purposes of this rule, we propose to define a ''*Nehmer* class member'' as a Vietnam veteran who has a covered herbicide disease, or a surviving spouse, child, or parent of a deceased Vietnam veteran who died from a covered herbicide disease.

The effective-date rules required by the *Nehmer* court orders apply only to benefits for disability or death caused by a disease for which VA has established a presumption of service connection under the Agent Orange Act of 1991, Public Law 102–4. For purposes of this rule, we propose to use the term ''covered herbicide disease'' and to define that term to mean a disease for which the Secretary of Veterans Affairs has established a presumption of service connection before October 1, 2002 pursuant to the Agent Orange Act of 1991, Public Law 102–4, excluding chloracne. As explained below in this notice, the effective-date rules of the *Nehmer* stipulation and court orders apply only to diseases for which a presumption of service connection is established under the authority granted by the Agent Orange Act of 1991, Public Law 102–4. Because the authority granted by that Act at the time the stipulation was entered extended only until September 30, 2002, any presumptions established after that date based on other legislative grants of rule-making authority are not within the scope of the *Nehmer* stipulation and court orders.

Although chloracne is a presumptive herbicide disease, we propose to exclude it from the definition of covered herbicide disease for purposes of this rule because claims and awards based on chloracne were not affected by any of the *Nehmer* court orders. VA established a presumption of service connection for chloracne effective September 25, 1985, and that presumption has remained in effect throughout the period relevant to the *Nehmer* litigation. In its May 3, 1989, order, the district court invalidated the portion of VA's regulation providing that conditions other than chloracne were not shown to be associated with herbicide exposure and it voided decisions made under that portion of the regulation. The court left intact the provision establishing a presumption of service connection for chloracne and did not void any decisions involving chloracne. Moreover, the *Nehmer* stipulation and order states that it applies to diseases service connected by VA ''in the future'' under the Agent Orange Act of 1991, Public Law 102–4. Because chloracne had been presumptively service connected since

1985, it was not affected by the stipulation and order.

Effective Date Rules

The effective-date rules stated in the proposed regulation reflect paragraph 5 of the *Nehmer* stipulation and order. That paragraph states separate rules governing the effective dates of awards granted upon readjudication of a claim where a prior denial was voided by the May 3, 1989 *Nehmer* order and the effective dates of awards granted upon adjudication of a claim filed after May 3, 1989.

With respect to the voided decisions, the stipulation and order provides that the effective date of an award made upon readjudication of the claim will be the later of the date the claim giving rise to the voided decision was filed (provided that the basis of the award is the same basis upon which the original claim was filed) or the date the disability arose or the death occurred. The stipulation and order states that the ''basis'' of the original claim refers to the disease or condition required, under provisions of a VA procedural manual, to be coded in the VA rating decision on the claim. The stipulation and order further states that the provisions of 38 U.S.C. 5110(b)(1) and (d)(1) will govern when applicable. Section 5110(b)(1) provides for a disability compensation effective date corresponding to the day following the veteran's release from service if the veteran's application is received within one year of that date. Section 5110(d)(1) provides for a DIC effective date corresponding to the first day of the month in which death occurred if the claimant's application is received within one year from the date of death.

With respect to claims filed after May 3, 1989, the stipulation and order provides that the effective date of benefits shall be the later of the date VA received the claim asserting the basis upon which the claim was granted or the date the disability arose or the death occurred.

We propose to provide paragraphs separately explaining the application of these rules to disability compensation awards and DIC awards. In view of the complexity of the *Nehmer* rules, we believe this level of detail will provide greater clarity.

Effective-Date Rules for Disability Compensation

1. Claims by Nehmer Class Members Denied Between September 25, 1985 and May 3, 1989

Section 3.816(c)(1) states that, if a *Nehmer* class member is entitled to disability compensation for a covered herbicide disease, and VA previously denied service connection for the same disease in a decision issued between September 25, 1985, the effective date of the invalidated regulation, and May 3, 1989, the effective date will be the later of the date VA received the claim on which the prior decision was based or the date the disability arose. This rule governs cases where a prior denial was voided by the district court's May 3, 1989 order. In an order dated February 11, 1999, the district court in *Nehmer* held that its 1989 order had voided claims rendered while former 38 CFR 3.311a(d) was in effect, provided that such claims denied compensation for a disease that VA later recognized as being associated with herbicide exposure. The court held that it is irrelevant whether the prior claim alleged that the disease was caused by herbicide exposure or whether the prior decision had referenced former § 3.311a(d). Accordingly, the only requirements for retroactive payment to a class member under proposed § 3.816(c)(1) would be that the decision have been rendered between September 25, 1985 and May 3, 1989—the period when former § 3.311a(d) was in effect—and that the decision have denied service connection for the same covered herbicide disease for which compensation has now been awarded.

Paragraph 5 of the *Nehmer* stipulation and order provides that the basis of the prior claim will be determined by reference to the diseases or conditions coded in the prior rating decision as required by provisions of a VA procedural manual. In accordance with the manual, VA rating decisions on claims for disability compensation ordinarily identify each claimed disease or injury by name and by a diagnostic code found in VA's Schedule for Rating Disabilities, which is located in 38 CFR part 4. There may be variations in both the terminology and diagnostic codes assigned to a particular disease depending on various aspects of the disease or associated conditions. For example, disability due to cancer of the larynx may have been rated as either a malignant neoplasm of the respiratory system (diagnostic code 6844) or residuals of a laryngectomy (diagnostic code 6819). Similarly, soft-tissue sarcomas may be described using different terminology or different diagnostic codes depending upon the body part or system primarily involved. Additionally, some diagnostic codes refer to broad classes of disease that encompass both covered and non-covered diseases. For example, diagnostic code 6819 (Neoplasms, malignant, any specified part of respiratory system exclusive of skin growths) may refer to either a covered disease (*e.g.*, lung cancer) or a non-covered disease (*e.g.*, nasal cancer).

We do not intend that minor, immaterial variations in terminology or diagnostic code would preclude application of the *Nehmer* rules. However, it must be established that the prior decision involved the same disease for which compensation has now been awarded, rather than a distinct condition arguably bearing some relation to the compensable disease because, for example, it involves the same body part or system. Accordingly, we propose to state that a prior decision will be construed as having denied compensation for the same disease if the prior decision denied compensation for a disease that reasonably may be construed as the same covered herbicide disease for which compensation has been awarded. We further propose to state that minor variations in the terminology used in the prior decision will not preclude a finding, based on the record at the time of the prior decision, that the decision denied service connection for the same covered herbicide disease.

2. Claims by Nehmer Class Members Pending on May 3, 1989, or Filed Between May 3, 1989 and the Effective Date of the Authorizing Statute or Regulation

Proposed § 3.816(c)(2) states that, if a class member is entitled to compensation for a covered herbicide disease and the class member's claim for compensation for that same disease was either pending on May 3, 1989 or was received by VA between that date and the effective date of the statute or regulation establishing a presumption of service connection for the disease, the effective date of compensation will be the later of the date VA received such claim or the date the disability arose. The *Nehmer* stipulation and order refers only to claims denied prior to May 3, 1989 and claims filed after that date. It does not expressly provide effective dates for claims that were filed prior to May 3, 1989 but not yet adjudicated by that date. Notwithstanding this apparent oversight, we propose to treat such claims in the same manner as claims filed after May 3, 1989, as no decision on a claim pending on May 3, 1989, could have been voided by the court order.

We propose to state that a claim will be considered a claim for compensation for a particular covered herbicide disease if the claimant's application and

other supporting statements and submissions may reasonably be viewed, under the standards ordinarily governing compensation claims, as indicating an intent to apply for compensation for the covered herbicide disability. This will merely ensure that the generally applicable provisions of statute and regulation governing claims will apply in determining whether and at what date a particular claim was filed for purposes of this rule.

3. Qualifying Claims by Nehmer Class Members Filed Within 1 Year After Separation From Service

We propose to state in § 3.816(c)(3) that, if a claim referenced in paragraph (c)(1) or (c)(2) was received by VA within one year after the date of the veteran's separation from service, the effective date of compensation will be the day following such separation. This would ensure that the principle stated in 38 U.S.C. 5110(b)(1) is applied, as required by the *Nehmer* stipulation and order. We note that the stipulation and order requires VA to apply section 5110(b)(1) to awards made upon readjudication of claims where a prior decision was voided by the court's 1989 order, but not to awards made in claims pending on or filed after May 3, 1989. Nevertheless, we propose to apply section 5110(b)(1) to claims pending on or filed after May 3, 1989, in order to ensure that the generally applicable provisions of that statute are applied in a consistent manner.

4. Other Claims

We propose to state in § 3.816(c)(4) that, if the requirements of paragraph (c)(1) or (c)(2) are not met, the effective date of the award shall be determined in accordance with 38 CFR 3.114 and 3.400, the provisions generally governing the effective dates of disability compensation. The United States Court of Appeals for Veterans Claims has held that the provisions of the *Nehmer* stipulation and order do not apply where a prior claim was denied before September 25, 1985. *See Williams* v. *Principi,* 15 Vet. App. 189 (2001) (en banc).

Similarly, the stipulation and order does not apply in cases where the veteran's initial claim for a covered herbicide disease was filed after the effective date of the regulations establishing a presumption of service connection for that disease. Further, application of the *Nehmer* stipulation to such cases would ordinarily be detrimental to veterans. Under 38 CFR 3.114, when disability compensation is awarded pursuant to a liberalizing regulation, the award may be made effective up to one year prior to the date of the claim, but no earlier than the effective date of the liberalizing regulation. In contrast, the *Nehmer* stipulation and order generally does not permit payment for any period prior to the date of the veteran's claim, except in the limited circumstances described in 38 U.S.C. 5110(b)(1) and (d)(1) involving claims filed within one year of the date of separation from service or the date of death.

Dependency and Indemnity Compensation

1. Claims by Nehmer Class Members Denied Between September 25, 1985 and May 3, 1989

Section 3.816(d)(1) states that, if a *Nehmer* class member is entitled to DIC for death caused by a covered herbicide disease, and VA previously denied DIC for the death in a decision issued between September 25, 1985 and May 3, 1989, the effective date will be the later of the date VA received the claim on which the prior decision was based or the date the death occurred. This rule governs cases where a prior denial was voided by the district court's May 3, 1989 order. Because DIC claims do not require assignment of disability ratings, decisions on DIC claims do not assign a diagnostic code corresponding to VA's rating schedule and may not identify the disease causing death with the same specificity necessary to decisions concerning disability compensation. Moreover, because the cause of death is usually established by the death certificate and medical records existing at death, DIC claims filed at different times ordinarily will not involve different conditions, as often occurs with respect to disability compensation claims. Accordingly, rather than requiring a specific finding that the prior denial of DIC expressly referenced the same covered herbicide disease that provided the basis for the current DIC award, we propose to require only that the prior decision issued between September 25, 1985 and May 3, 1989, have denied DIC for the same death.

2. Claims By Nehmer Class Members Pending on May 3, 1985 or Filed Between May 3, 1989 and the Effective Date of the Authorizing Statute or Regulation

Proposed § 3.816(d)(2) states that, if the class member's claim for DIC for the death was either pending on May 3, 1989 or was received by VA between that date and the effective date of the statute or regulation establishing a presumption of service connection for the disease causing the death, the effective date of DIC will be the later of the date VA received such claim or the date the death occurred. For the reasons stated above with respect to disability compensation, we propose to include claims filed before May 3, 1989, but still pending on that date, even though the *Nehmer* stipulation and order does not expressly provide for such claims.

The provisions of 38 U.S.C. 5101(b)(1) and 38 CFR 3.152(b)(1) state that a claim by a surviving spouse or child for death pension shall be considered a claim for DIC as well. We propose to reference this requirement in the proposed rule. Further, for the same reasons stated above with respect to disability compensation claims, we propose to state that a claim will be considered a claim for DIC if the claimant's application and other supporting statements and submissions may reasonably be viewed, under the standards ordinarily governing DIC claims, as indicating an intent to apply for DIC.

3. Qualifying Claims by Nehmer Class Members Filed Within 1 Year After Date of Death

We propose to state in § 3.816(d)(3) that, if a claim referenced in paragraph (d)(1) or (d)(2) was received by VA within one year after the date of the veteran's death, the effective date of DIC will be the first day of the month of death. This would ensure that the principle stated in 38 U.S.C. 5110(d)(1) is applied, as required by the *Nehmer* stipulation and order. We note that the stipulation and order requires VA to apply section 5110(d)(1) to awards made upon readjudication of claims where a prior decision was voided by the court's 1989 order, but not to awards made in claims pending on or filed after May 3, 1989. Nevertheless, we propose to apply section 5110(d)(1) to claims pending on or filed after May 3, 1989, in order to ensure that the generally applicable provisions of that statute are applied in a consistent manner.

4. Other Claims

For the reasons stated above with respect to disability compensation, we propose to state in § 3.816(d)(4) that, if the requirements of paragraph (d)(1) or (d)(2) are not met, the effective date of DIC will be governed by 38 CFR 3.114 and 3.400.

Effect of Other Provisions

We propose to state in § 3.816(e)(1) that, if the requirements of paragraphs (c)(1) or (c)(2) or (d)(1) or (d)(2) are met, the effective date of benefits will be determined as provided by this rule, without regard to any contrary provision

in 38 U.S.C. 5110(g) or 38 CFR 3.114. As noted above, the effective-date rules required by the *Nehmer* court create a limited exception to that statute and regulation. In order to avoid confusion among VA personnel, claimants, and claimants' representatives regarding the effect of this exception, we believe it is necessary to state clearly that the *Nehmer* rules shall be applied, when they are applicable, without regard to 38 U.S.C. 5110(g) or 38 CFR 3.114.

We also propose to state that the effective-date provisions in this rule will not apply if a statute or regulation other than 38 U.S.C. 5110(g) or 38 CFR 3.114 would bar a retroactive payment that would otherwise be available under the *Nehmer* rules. For example, if a DIC claimant did not qualify as a surviving spouse at the time of the prior DIC claim, VA would lack authority to pay DIC to the claimant for periods relevant to such claim, even if the claimant later attains the status of a surviving spouse, based, for example, upon termination of remarriage. The *Nehmer* court orders require VA to give retroactive effect to its herbicide regulations, but do not purport to eradicate statutory bars to benefits that would preclude payment even if the herbicide regulations apply retroactively.

Proposed paragraph (e)(2) would explain the effect of section 505 of Public Law 104–275, which prohibits VA from making retroactive payments in certain circumstances where a benefit award is based on service in the Republic of Vietnam prior to August 5, 1964. Prior to January 1, 1997, the presumptions of service connection for diseases associated with herbicide exposure applied only to veterans who served in the Republic of Vietnam during the Vietnam era, which was then defined by statute and regulation to encompass the period beginning on August 5, 1964 and ending on May 7, 1975. In 1996, Congress enacted Public Law 104–275, section 505(b) of which extended those presumptions to veterans who served in the Republic of Vietnam during the period between January 9, 1962, and August 4, 1964. Congress specified, in section 505(d) of Public Law 104–275, that the amendment would take effect on January 1, 1997, and that ''[n]o benefit may be paid or provided by reason of such amendments for any period before such date.'' Accordingly, some claims may have been denied prior to January 1, 1997, because the claimants' service did not meet the then-existing statutory requirement of service during the Vietnam era. Although some such claimants may now be entitled to presumptive service connection under the liberalizing 1996 statute, Congress has prohibited VA from paying retroactive benefits based on the amendment made by Public Law 104–275.

We propose to state that the retroactive payment provisions of these proposed rules do not apply if the veteran's Vietnam service ended before August 5, 1964 and the class member's prior claim for benefits was denied by VA before January 1, 1997. In such cases, the denial was required by statute and VA is prohibited from paying retroactive benefits based on the prior claim. We propose to state that the effective date of any subsequent award in such cases will be governed by 38 U.S.C. 5110(g). We further propose to state that, if a veteran's Vietnam service ended before August 5, 1964 and the class member's claim for benefits was pending on or was received by VA after January 1, 1997, the effective date shall be the later of the effective date provided for in the proposed rules or January 1, 1997. This would conform to the requirement in Public Law 104–275 that VA may not pay benefits in such cases for any period before January 1, 1997.

Payment of Benefits to Survivors of Deceased Beneficiaries

1. Requirements of the Nehmer Court Orders

In its December 12, 2000 order, the district court held that, when a *Nehmer* class member entitled to retroactive benefits under the *Nehmer* stipulation and order dies prior to receiving payment of such benefits, VA must pay the full amount of such benefits to the class member's estate. Under 38 U.S.C. 5121 and 38 CFR 3.1000, when any monetary benefits remain due and unpaid at the time of a beneficiary's death, VA may pay to certain individuals only the portion of such benefits that accrued during the two-year period preceding death. Further, VA cannot pay any such accrued benefits unless the appropriate payee files a claim for accrued benefits within one year after the date of death. However, the *Nehmer* court held that these restrictions do not apply to payments of amounts payable pursuant to the *Nehmer* stipulation and order. Rather, the court held that VA must pay the entire amount of such retroactive payment to the class member's estate and must do so without requiring a claim for accrued benefits.

2. Persons Eligible for Payments

In implementing the court's order, VA found that it was impractical in most cases to pay retroactive benefits to a class member's estate. Although VA claims files ordinarily contain information identifying persons who would be eligible for accrued benefits under section 5121 of title 38, United States Code, they generally do not contain information concerning the estates of veterans and other class members. Further, in a substantial number of cases, entitlement to retroactive payments under the *Nehmer* stipulation and order is established several months or even years after the class member's death, at a time when the decedent's estate would have been finally settled. In such cases, there may be no existing estate to receive payment. Even if an estate exists, paying benefits to the estate would arguably contravene the fundamental purpose of the veterans' benefits laws to provide payments for the use of the veteran and his or her family. Section 5121 provides that accrued benefits shall be paid to the decedent's surviving spouse, children, or dependent parents (in that line of succession), but does not permit payment to a decedent's estate. Although this statute limits the amount of accrued benefits payable, it clearly indicates that the accrued benefits are intended for the use of the decedent's family rather than the decedent's estate and creditors. If benefits were paid to a decedent's estate, they would potentially be subject to claims of creditors of the estate, with the possibility that the decedent's family would obtain no benefit from such payments. This would improperly deprive the decedent's family of the benefits expressly authorized by section 5121(a) (to the extent the payment to the estate encompassed benefits due and unpaid for the two-year period preceding death), and would contravene the general purpose of veterans benefits laws to provide benefits for the personal use of the veteran and his or her family.

After consulting with representatives of the *Nehmer* class, VA decided to issue payment directly to the persons who would have been eligible to receive accrued benefits under 38 U.S.C. 5121(a) at the time of the class member's death, rather than withholding all payment. We believe this procedure is consistent with the purpose of the *Nehmer* court orders and is more beneficial to class members, in view of the impracticability of locating and paying estates and the possibility that payments to estates may not inure to the benefit of the class member's survivors. We also believe that this procedure ensures that payments are made in the

manner most consistent with the language and purpose of existing law.

Consistent with this practice, we propose to state in paragraph 3.816(f)(1) that, if a *Nehmer* class member dies prior to receiving payment of retroactive benefits due pursuant to the *Nehmer* stipulation and order, VA will pay the full amount of such unpaid benefits directly to the person or persons who would have been eligible to receive accrued benefits under 38 U.S.C. 5121(a)(2)–(a)(4) at the time of the class member's death (*i.e.*, the class member's spouse, children (in equal shares), or dependent parents (in equal shares), in that order of preference). If no such survivors are in existence, VA would pay as much of the unpaid retroactive benefits as necessary to reimburse the person who bore the expense of the class member's last sickness and burial, in the same manner as provided in 38 U.S.C. 5121(a)(5) for accrued benefits.

Paragraph (f)(1) would further provide that a person's status as the spouse, child, or dependent parent of the class member would be determined as of the date of the class member's death, rather than the date that payment is made under this rule. As noted above, some class members may have died several months or years before payment can be made under these rules. Due to the lapse of time, a person who qualified as the class member's spouse or child on the date of the class member's death may no longer meet the statutory or regulatory definition of spouse or child, due to changes in their age or marital status. For example, a ''child'' is generally defined in 38 U.S.C. 101(4)(A) to refer to an unmarried child who is (with certain exceptions) under the age of eighteen years. A person who met this definition on the date of a class member's death may have married or attained the age of eighteen years before VA releases payment of unpaid retroactive benefits due to the class member. Because the *Nehmer* court orders were generally intended to correct past errors, we propose to authorize payment to persons who would have been eligible for payment as a spouse, child, or dependent parent on the date of the class member's death, irrespective of subsequent changes in age or marital status that would otherwise affect their entitlement to payment.

In view of language in the *Nehmer* court's order requiring payments to estates, however, we believe it is necessary to seek an order from that court clarifying or modifying its prior order to make clear that VA may release payments in the manner proposed. Accordingly, we intend to request such an order from the district court concurrently with the publication of these proposed rules.

3. Inapplicability of Certain Accrued Benefit Requirements

As stated above, the district court indicated that the statutory two-year limit on payment of accrued benefits and the statutory requirement that a qualified payee or payees file a claim for accrued benefits do not apply to payments of retroactive benefits due and unpaid to a *Nehmer* class member at the time of death. Accordingly, we propose to state, in paragraph (f)(2), that those requirements do not apply. We further propose to state that, if a class member dies before receiving payment of retroactive benefits due to him or her, VA will pay the amount to the known payee(s) without requiring a claim. A veteran's VA claim file will often contain information identifying the surviving spouse, children, or parents of a class member. By clarifying that VA will release payment based on such information without awaiting communication from such survivors, this provision would permit expeditious release of payments.

4. Identifying Payees

We propose to state, in paragraph (f)(3), that VA shall make reasonable efforts to identify appropriate payees based on information contained in the veteran's claims file. We propose to state that, if further information is needed to determine whether an appropriate payee exists, or whether there is any person having precedence equal to or greater than a known survivor, VA will request such information from a known survivor or the class member's authorized representative if the claims file contains sufficient contact information. We also propose to state that, before releasing payment to a known survivor, VA will request information from the survivor concerning the possible existence of other survivors with equal or greater priority for payment, unless the circumstances clearly indicate that such a request is unnecessary. For example, if the claims file contained the name and address of a child of the deceased class member, VA would contact the child to inquire whether there is a surviving spouse or any other children of the class member in existence. In seeking to identify appropriate payees, VA necessarily must rely on information in the claims file. VA does not have the resources to conduct independent investigations of estate issues.

We propose to state that, after making reasonable efforts to identify the appropriate payee(s), if VA releases the full amount of retroactive payments to a payee, VA generally may not thereafter pay any portion of such benefits to any other individual, unless VA is able to recover any payment previously released.

5. Prohibition On Duplicate Payments

We propose to state, in paragraph (f)(4), that, payment of benefits pursuant to this rule shall bar a later claim by any individual for payment of all or any part of such benefits as accrued benefits under 38 U.S.C. 5121 and 38 CFR 3.1000. The district court ordered VA to release all retroactive amounts due a class member at the time of death under the *Nehmer* stipulation and order. This would necessarily include amounts that otherwise would be payable as accrued benefits under 38 U.S.C. 5121. Accordingly, once payment has been made pursuant to the court's order, no retroactive benefits would remain for payment to any person as accrued benefits. Inasmuch as this rule applies only to retroactive benefits payable for a covered herbicide disease pursuant to the 1991 stipulation and order, it would not preclude a survivor's right to seek accrued benefits under section 5121 in the event a deceased class member was entitled at death to benefits for conditions other than a covered herbicide disease.

Awards Not Covered by the Nehmer Rules

We propose to state, in § 3.816(g), that the provisions of this rule do not apply to awards of disability compensation or DIC for disability or death due to a disease for which the Secretary of Veterans Affairs establishes a presumption of service connection after September 30, 2002. The *Nehmer* stipulation and order applies to awards based on diseases for which the Secretary establishes a presumption of service connection pursuant to the Agent Orange Act of 1991, Public Law 102–4. The Act established a sunset date of September 30, 2002, for the Secretary to establish such presumptions. Accordingly, the *Nehmer* stipulation and order applies only to awards based on presumptions established within the time frame specified in the Agent Orange Act of 1991, Public Law 102–4.

The Agent Orange Act of 1991, Public Law 102–4, added section 1116 to title 38, United States Code. Section 1116(b) authorized the Secretary of Veterans Affairs to issue regulatory presumptions of service connection for diseases associated with herbicide exposure. Section 1116(e), as added by the Act, stated that section 1116(b) would cease

to be effective 10 years after the first day of the fiscal year in which the NAS transmitted its first report to VA. The first NAS report was transmitted in June 1993, during the fiscal year that began on October 1, 1992. Accordingly, under the Act, VA's authority to issue regulatory presumptions as specified in section 1116(b) would have expired on September 30, 2002.

In December 2001, Congress enacted the Veterans Education and Benefits Expansion Act of 2001 (Benefits Expansion Act), Public Law 107–103, section 201(d) of which extended VA's authority under section 1116(b) through September 30, 2015. Pursuant to this statute, VA may issue new regulations between October 1, 2002 and September 30, 2015 establishing additional presumptions of service connection for diseases that are found to be associated with herbicide exposure based on evidence contained in future NAS reports. Because presumptions established pursuant to the authority of the Benefits Expansion Act would be beyond the scope of the *Nehmer* stipulation and order, the effective-date provisions of the stipulation and order, as stated in this proposed rule, would not apply to claims based on diseases service-connected pursuant to the Benefits Expansion Act of 2001.

Both the district court and the Court of Appeals for the Ninth Circuit stated that the *Nehmer* stipulation and order applies only to awards based on presumptions issued within the time period established by the Agent Orange Act of 1991, Public Law 102–4. The district court noted that the retroactive payment provisions of the stipulation and order are ''expressly tied'' to the Agent Orange Act of 1991, Public Law 102–4, and that ''the Stip. & Order is not therefore boundless.'' *Nehmer* v. *United States Department of Veterans Affairs*, No. CV–86–6160 TEH (N.D. Cal. Dec. 12, 2000). In a decision issued April 1, 2002, the Ninth Circuit stated that, ''the district court was careful to prescribe temporal limits on the effect of the consent decree, with which we agree.'' *Nehmer* v. *Veterans'* Administration, 284 F.3d 1158, 1162 n.3. (9th Cir. 2002), *reh'g denied*.

In its December 12, 2000, order, the district court held that the 1991 stipulation and order must be interpreted in accordance with general principles of contract law. It is well established that, unless the parties provide otherwise, a contract is presumed to incorporate the law that existed at the time the contract was made. *See Norfolk & Western Ry. Co.* v. *American Train Dispatchers' Ass'n*, 499 U.S. 117, 129–30 (1991). A subsequent change in the law cannot retrospectively alter the terms of the agreement. *See Florida East Coast Ry. Co.* v. *CSX Transportation*, Inc., 42 F.3d 1125, 1129–30 (7th Cir. 1994). Accordingly, the enactment of the Benefits Expansion Act of 2001 does not alter the scope of the 1991 stipulation and order.

Because the Benefits Expansion Act of 2001, Public Law 107–103, established rights and duties that did not exist under the Agent Orange Act of 1991, Public Law 102–4, any regulations issued pursuant to the authority of the Benefits Expansion Act of 2001 are beyond the express scope of the *Nehmer* stipulation and order. Accordingly, the stipulation and order provides no authority for VA to pay retroactive benefits under such regulations in a manner contrary to the governing statutes and regulations concerning the effective dates of awards. Proposed paragraph 3.406(g) would reflect this fact. This provision would make clear that awards based on regulations issued pursuant to the Benefits Expansion Act of 2001 would be governed by the generally applicable provisions governing the effective dates of benefit awards.

Executive Order 12866

This regulatory amendment has been reviewed by the Office of Management and Budget under the provisions of Executive Order 12866, Regulatory Planning and Review, dated September 30, 1993.

Paperwork Reduction Act

This document contains no provisions constituting a collection of information under the Paperwork Reduction Act (44 U.S.C. 3501–3521).

Unfunded Mandates

The Unfunded Mandates Reform Act requires, at 2 U.S.C. 1532, that agencies prepare an assessment of anticipated costs and benefits before developing any rule that may result in an expenditure by State, local, or tribal governments, in the aggregate, or by the private sector of $100 million or more in any given year. This rule would have no consequential effect on State, local, or tribal governments.

Regulatory Flexibility Act

The Secretary hereby certifies that this regulatory amendment will not have a significant economic impact on a substantial number of small entities as they are defined in the Regulatory Flexibility Act (RFA), 5 U.S.C. 601–612. The reason for this certification is that these amendments would not directly affect any small entities. Only VA beneficiaries and their survivors could be directly affected. Therefore, pursuant to 5 U.S.C. 605(b), these amendments are exempt from the initial and final regulatory flexibility analysis requirements of sections 603 and 604.

Catalog of Federal Domestic Assistance

The Catalog of Federal Domestic Assistance program numbers are 64.109, and 64.110.

List of Subjects in 38 CFR Part 3

Administrative practice and procedure, Claims, Disability benefits, Herbicides, Veterans, Vietnam.

Approved: November 4, 2002.

Anthony J. Principi,

Secretary of Veterans Affairs.

For the reasons set forth in the preamble, 38 CFR part 3 is proposed to be amended as follows:

PART 3—ADJUDICATION

Subpart A—Pension, Compensation, and Dependency and Indemnity Compensation

1. The authority citation for part 3, subpart A continues to read as follows:

Authority: 38 U.S.C. 501(a), unless otherwise noted.

2. Section 3.816 is added to read as follows:

§ 3.816 Awards under the Nehmer Court Orders for disability or death caused by a condition presumptively associated with herbicide exposure.

(a) *Purpose.* This section states effective-date rules required by orders of a United States district court in the class-action case of *Nehmer* v. *United States Department of Veterans Affairs*, No. CV–86–6160 TEH (N.D. Cal.).

(b) *Definitions.* For purposes of this section'

(1) *Nehmer class member* means:

(i) A Vietnam veteran who has a covered herbicide disease; or

(ii) A surviving spouse, child, or parent of a deceased Vietnam veteran who died from a covered herbicide disease.

(2) *Covered herbicide disease* means a disease for which the Secretary of Veterans Affairs has established a presumption of service connection before October 1, 2002 pursuant to the Agent Orange Act of 1991, Public Law 102–4, other than chloracne. Those diseases are:

(i) Type 2 Diabetes (Also known as type II diabetes mellitus or adult-onset diabetes).

(ii) Hodgkin's disease.

(iii) Multiple myeloma.

(iv) Non-Hodgkin's lymphoma.

(v) Acute and Subacute peripheral neuropathy.

(vi) Porphyria cutanea tarda.

(vii) Prostate cancer.

(viii) Respiratory cancers (cancer of the lung, bronchus, larynx, or trachea).

(ix) Soft-tissue sarcoma (as defined in § 3.309(e)).

(c) *Effective date of disability compensation.* If a *Nehmer* class member is entitled to disability compensation for a covered herbicide disease, the effective date of the award will be as follows:

(1) If VA denied compensation for the same covered herbicide disease in a decision issued between September 25, 1985 and May 3, 1989, the effective date of the award will be the later of the date VA received the claim on which the prior denial was based or the date the disability arose, except as otherwise provided in paragraph (c)(3) of this section. A prior decision will be construed as having denied compensation for the same disease if the prior decision denied compensation for a disease that reasonably may be construed as the same covered herbicide disease for which compensation has been awarded. Minor differences in the terminology used in the prior decision will not preclude a finding, based on the record at the time of the prior decision, that the prior decision denied compensation for the same covered herbicide disease.

(2) If the class member's claim for disability compensation for the covered herbicide disease was either pending before VA on May 3, 1989, or was received by VA between that date and the effective date of the statute or regulation establishing a presumption of service connection for the covered disease, the effective date of the award will be the later of the date such claim was received by VA or the date the disability arose, except as otherwise provided in paragraph (c)(3) of this section. A claim will be considered a claim for compensation for a particular covered herbicide disease if the claimant's application and other supporting statements and submissions may reasonably be viewed, under the standards ordinarily governing compensation claims, as indicating an intent to apply for compensation for the covered herbicide disability.

(3) If the class member's claim referred to in paragraph (c)(1) or (c)(2) of this section was received within one year from the date of the class member's separation from service, the effective date of the award shall be the day following the date of the class member's separation from active service.

(4) If the requirements of paragraph (c)(1) or (c)(2) of this section are not met, the effective date of the award shall be determined in accordance with §§ 3.114 and 3.400.

(d) *Effective date of dependency and indemnity compensation (DIC).* If a Nehmer class member is entitled to DIC for a death due to a covered herbicide disease, the effective date of the award will be as follows:

(1) If VA denied DIC for the death in a decision issued between September 25, 1985 and May 3, 1989, the effective date of the award will be the later of the date VA received the claim on which such prior denial was based or the date the death occurred, except as otherwise provided in paragraph (d)(3) of this section.

(2) If the class member's claim for DIC for the death was either pending before VA on May 3, 1989, or was received by VA between that date and the effective date of the statute or regulation establishing a presumption of service connection for the covered herbicide disease that caused the death, the effective date of the award will be the later of the date such claim was received by VA or the date the death occurred, except as otherwise provided in paragraph (d)(3) of this section. In accordance with § 3.152(b)(1), a claim by a surviving spouse or child for death pension will be considered a claim for DIC. In all other cases, a claim will be considered a claim for DIC if the claimant's application and other supporting statements and submissions may reasonably be viewed, under the standards ordinarily governing DIC claims, as indicating an intent to apply for DIC.

(3) If the class member's claim referred to in paragraph (d)(1) or (d)(2) of this section was received within one year from the date of the veteran's death, the effective date of the award shall be the first day of the month in which the death occurred.

(4) If the requirements of paragraph (d)(1) or (d)(2) of this section are not met, the effective date of the award shall be determined in accordance with §§ 3.114 and 3.400.

(e) *Effect of other provisions affecting retroactive entitlement.*—(1) *General.* If the requirements specified in paragraphs (c)(1) or (c)(2) or (d)(1) or (d)(2) of this section are satisfied, the effective date shall be assigned as specified in those paragraphs, without regard to the provisions in 38 U.S.C. 5110(g) or § 3.114 prohibiting payment for periods prior to the effective date of the statute or regulation establishing a presumption of service connection for a covered herbicide disease. However, the provisions of this section will not apply if payment to a *Nehmer* class member based on a claim described in paragraph (c) or (d) of this section is otherwise prohibited by statute or regulation, as, for example, where a class member did not qualify as a surviving spouse at the time of the prior claim or denial.

(2) *Claims Based on Service in the Republic of Vietnam Prior To August 5, 1964.* If a claim referred to in paragraph (c) or (d) of this section was denied by VA prior to January 1, 1997, and the veteran's service in the Republic of Vietnam ended before August 5, 1964, the effective-date rules of this regulation do not apply. The effective date of benefits in such cases shall be determined in accordance with 38 U.S.C. 5110. If a claim referred to in paragraph (c) or (d) of this section was pending before VA on January 1, 1997, or was received by VA after that date, and the veteran's service in the Republic of Vietnam ended before August 5, 1964, the effective date shall be the later of the date provided by paragraph (c) or (d) of this section or January 1, 1997.

(Authority: Pub. L. 104–275, sec. 505)

(f) *Payment of Benefits to Survivors of Deceased Beneficiaries.*—(1) *General.* If a *Nehmer* class member entitled to retroactive benefits pursuant to paragraphs (c)(1) through (c)(3) or (d)(1) through (d)(3) of this section dies prior to receiving payment of any such benefits, VA shall pay such unpaid retroactive benefits as follows:

(i) VA will pay the full amount of unpaid retroactive benefits to the living person or persons who, at the time of the class member's death, would have been eligible to receive payment of any accrued benefits under 38 U.S.C. 5121(a)(2)–(a)(4). For purposes of this paragraph, a person's status as the spouse, child, or dependent parent of a veteran shall be determined as of the date of the class member's death, irrespective of the person's age or marital status at the time payment is made under this section. The determination shall be based on evidence on file at the date of death. If the person or persons who would have been eligible to receive accrued benefits at the time of the class member's death are now deceased, VA shall pay the full amount of unpaid retroactive benefits to the living person or persons who were next in priority under 38 U.S.C. 5121(a)(2)–(a)(4) at the time of the class member's death.

(ii) If there is no living person eligible for payment under paragraph (f)(1)(i) of this section, VA will pay to the person who bore the expense of the class member's last sickness and burial only

such portion of the unpaid retroactive benefits as is necessary to reimburse the person for such expense.

(2) *Inapplicability of certain accrued benefit requirements.* The provisions of 38 U.S.C. 5121(a) and § 3.1000(a) limiting payment of accrued benefits to amounts due and unpaid for a period not to exceed two years do not apply to payments under this section. The provisions of 38 U.S.C. 5121(c) and § 3.1000(c) requiring survivors to file claims for accrued benefits also do not apply to payments under this section. When a *Nehmer* class member dies prior to receiving retroactive payments under this section, VA will pay the amount to an identified payee in accordance with paragraph (f)(1) of this section without requiring an application from the payee. Prior to releasing such payment, however, VA may ask the payee to provide further information as specified in paragraph (f)(3) of this section.

(3) *Identifying Payees.* VA shall make reasonable efforts to identify the appropriate payee(s) under paragraph (f)(1) of this section based on information in the veteran's claims file. If further information is needed to determine whether any appropriate payee exists or whether there are any persons having equal or higher precedence than a known prospective payee, VA will request such information from a survivor or authorized representative if the claims file provides sufficient contact information. Before releasing payment to an identified payee, VA will ask the payee to state whether there are any other survivors of the class member who may have equal or greater entitlement to payment under this section, unless the circumstances clearly indicate that such a request is unnecessary. If, following such efforts, VA releases the full amount of unpaid benefits to a payee, VA may not thereafter pay any portion of such benefits to any other individual, unless VA is able to recover the payment previously released.

(4) *Bar to accrued benefit claims.* Payment of benefits pursuant to paragraph (f)(1) of this section shall bar a later claim by any individual for payment of all or any part of such benefits as accrued benefits under 38 U.S.C. 5121 and § 3.1000.

(g) *Awards covered by this section.* This section applies only to awards of disability compensation or DIC for disability or death caused by a disease listed in paragraph (b)(2) of this section.

(Authority: 38 U.S.C. 501)

[FR Doc. 03–1834 Filed 1–27–03; 8:45 am]

BILLING CODE 8320–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[NV–039–0053; FRL–7444–1]

Approval and Promulgation of State Implementation Plans; State of Nevada; Clark County

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve state implementation plan (SIP) revisions submitted by the State of Nevada to provide for attainment of the carbon monoxide (CO) national ambient air quality standards (NAAQS) in the Clark County Nonattainment Area. EPA is proposing to approve the SIP revisions under provisions of the Clean Air Act (CAA or the Act) regarding EPA action on SIP submittals, SIPs for national primary and secondary ambient air quality standards, and plan requirements for nonattainment areas.

DATES: Written comments on this proposal must be received by February 27, 2003.

ADDRESSES: Comments should be addressed to the EPA contact below. You may inspect and copy the rulemaking docket for this notice at the following location during normal business hours. We may charge you a reasonable fee for copying parts of the docket.

Steven Barhite, Chief, Environmental Protection Agency, Region 9, Air Division, Air Planning Office (AIR–2), 75 Hawthorne Street, San Francisco, CA 94105–3901.

Copies of the SIP materials are also available for inspection at the addresses listed below:

Nevada Dept. of Conservation and Natural Resources, Division of Environmental Protection, 333 West Nye Lane, Room 138, Carson City, NV 89706.

Clark County Department of Air Quality Management, 500 S. Grand Central Parkway, Las Vegas, NV 89155.

FOR FURTHER INFORMATION CONTACT: Karina O'Connor, Air Planning Office (AIR–2), Air Division, U.S. EPA, Region 9, 75 Hawthorne Street, San Francisco, CA 94105–3901. Telephone: (775) 833–1276. E-mail: *oconnor.karina@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document, ''we,'' ''us'' and ''our'' refer to EPA.

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I. Background

A. Why Is CO an Air Quality Problem?

Carbon monoxide (CO) is a colorless, odorless gas emitted in combustion processes. In Clark County, like most urban areas, CO comes primarily from tailpipe emissions of cars and trucks.[1] Exposure to elevated CO levels is associated with impairment of visual perception, work capacity, manual dexterity, and learning ability, and with illness and death for those who already suffer from cardiovascular disease, particularly angina or peripheral vascular disease.

B. How Are CO Levels Assessed?

Under section 109 of the Act, we have established primary, health-related NAAQS for CO: 9 parts per million (ppm) averaged over an 8-hour period, and 35 ppm averaged over 1 hour. Attainment of the 8-hour CO NAAQS is achieved if not more than one non-overlapping 8-hour average per monitoring site per year exceeds 9 ppm in any consecutive 2-year period (values below 9.5 are rounded down to 9.0 and are not considered exceedances).

[1] In the 1996 base year inventory, on-road vehicles accounted for approximately 86 percent of CO emissions while nonroad sources contributed roughly 11 percent and stationary and area sources contributed roughly 3 percent.

Clark County has never exceeded the 1-hour NAAQS. For this reason, the Clark County CO plan and this action address only the 8-hour NAAQS. The area has been monitoring ambient air for CO levels since the early 1980's. In 1985, the Las Vegas area recorded 41 exceedances of the 8-hour NAAQS; however, the area has recorded less than 5 exceedances each year since the early 1990's. Most of the CO exceedances in Clark County occur during the months of January, February, and December, with peak concentrations typically in the evenings. The last exceedances of the eight-hour CO NAAQS were recorded in 1998 at the Sunrise Avenue site in Las Vegas, and while the ambient monitoring data provides a preliminary basis for EPA to propose an attainment finding for Las Vegas Valley, this notice does not address that issue. EPA will publish an attainment finding for Las Vegas Valley in a separate notice, if appropriate following a detailed review of the monitoring data.

C. What Clean Air Act Statutory, Regulatory and Policy Requirements Must Las Vegas Meet To Improve CO Levels?

Las Vegas Valley was first designated as a CO nonattainment area in 1978. See 43 FR 8962, 9012 (March 3, 1978). The CAA Amendments of 1977 required states to prepare plans to achieve the NAAQS in nonattainment areas. The original attainment deadline was 1982. EPA conditionally approved the initial CO plan for Las Vegas Valley into the Nevada SIP in 1981. See 46 FR 21758 (April 14, 1981). EPA removed the conditions on the CO plan in 1982. See 47 FR 15790 (April 13, 1982.) Updated plans were required for nonattainment areas, like Las Vegas Valley, that did not achieve the original 1982 deadline. EPA approved this updated plan into the Nevada SIP in 1984. See 49 FR 44208 (November 5, 1984) and 40 CFR 52.1470(c)(32).

The Federal CAA was substantially amended in 1990 to establish new planning requirements and attainment deadlines for the NAAQS. Under section 107(d)(1)(C) of the Act, areas designated nonattainment prior to enactment of the 1990 amendments, including Las Vegas Valley, were designated nonattainment by operation of law.[2] 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 Las Vegas Valley area, were classified as moderate. (The design value for Las Vegas Valley for initial classification purposes was 14.4 ppm, which was based on monitoring data from the late 1980's.) These nonattainment designations and classifications were codified into 40 CFR part 81. See 56 FR 56694 (November 6, 1991). Section 172 of the Act contains general requirements applicable to SIP revisions for nonattainment areas, and sections 186 and 187 of the Act set out additional air quality planning requirements for CO nonattainment areas.

The most fundamental of these provisions is the requirement that CO nonattainment areas with design values greater than 12.7 ppm submit a SIP revision demonstrating attainment of the NAAQS as expeditiously as practicable but no later than the deadline applicable to the area's classification: December 31, 1995, for moderate areas. See CAA sections 186(a)(1) and 187(a)(7). Such a demonstration must provide enforceable measures to achieve emission reductions each year leading to emissions at or below the level predicted to result in attainment of the NAAQS throughout the nonattainment area.

Las Vegas Valley failed to reach attainment by December 31, 1995, but, under section 186(a)(4) of the Act, the State of Nevada requested, and EPA granted, a one-year extension of the attainment date to December 31, 1996. See 61 FR 57331 (November 6, 1996). However, in the first quarter of 1996, Clark County recorded three exceedances of the CO standard at the East Charleston monitoring station and thus was unable to show attainment of the standard by the new attainment date and could not qualify for an additional one-year extension under section 186(a)(4) of the Act.

Subsequently, on October 2, 1997, we published a final rule that found that the Las Vegas Valley CO nonattainment area did not attain the CO NAAQS by the applicable attainment date and that reclassified the area from ''moderate'' to ''serious'' nonattainment under section 186(b)(2) of the Act.[3] See 62 FR 51604 (October 2, 1997). Areas reclassified as serious are given more time to develop a SIP revision and a new attainment date but are subject to additional requirements beyond those that are required in moderate nonattainment areas. For Las Vegas Valley, the effect of the reclassification to ''serious'' was to allow Nevada 18 months from the effective date of the reclassification to submit a new SIP demonstrating attainment of the CO NAAQS as expeditiously as practicable but no later than December 31, 2000, the CAA attainment date for serious CO nonattainment areas.

We have issued a ''General Preamble'' describing the agency's preliminary views on SIP revisions submitted under Title I of the Act. See generally 57 FR 13498 (April 16, 1992) and 57 FR 18070 (April 28, 1992). The reader should refer to the General Preamble for a more detailed discussion of our preliminary interpretations of Title I requirements. In this proposed rulemaking action, we are applying these interpretations to the Las Vegas Valley CO SIP submittals, taking into consideration the specific factual issues presented.

D. Has EPA Acted on Prior and Related Las Vegas Valley CO SIP Revisions?

Under a letter dated November 13, 1992, the Nevada Division of Environmental Protection (''NDEP'') submitted the first CO attainment plan for Las Vegas Valley (''1992 CO plan'') under the Clean Air Act Amendments of 1990. Because the 1992 CO plan was superceded by the 1995 CO plan, discussed below, we will be taking no action on that plan.

From 1992 through 1994, the State of Nevada submitted various required CO SIP elements to us for Las Vegas Valley, and, in 1995, the State of Nevada submitted a new CO attainment plan for Las Vegas Valley under a letter from NDEP dated November 8, 1995 (''1995 CO plan''). The 1995 CO plan was adopted by the Clark County Board of Commissioners on October 17, 1995. The 1995 CO plan was deemed complete by operation of law on May 13, 1996 under section 110(k)(1)(B) of the Act. The 1995 CO plan included emissions inventories, including motor vehicle emissions estimates referred to as budgets, and several CO control measures, including a specification for Reid Vapor Pressure (RVP) of wintertime gasoline sold in Clark County, a wintertime oxygenated fuels program, contingency measures related to technician training for the vehicle inspection and maintenance (''I/M'') program and heavy duty vehicle inspection, and an additional commitment to implement an expanded remote vehicle sensing program.

Until today's notice, the only portion of the 1995 CO plan that was acted upon

[2] The CO nonattainment area is the ''Las Vegas Valley Hydrographic Area 212'' within Clark County. See 40 CFR 81.329.

[3] Title 40 of the Code of Federal Regulations, part 81, § 81.329 (40 CFR 81.329) was not updated at that time to reflect this final action but was recently updated in a separate action. See 67 FR 12474 (March 19, 2002).

by us was the motor vehicle emission budgets. We were required to make positive or negative adequacy determinations on all emission budgets in response to the March 2, 1999 court decision in *Environmental Defense Fund* v. *EPA,* 167 F.3d 641 (D.C. Cir. 1999). We acted on the motor vehicle emission budgets contained in the 1995 CO plan on May 5, 1999. See 64 FR 31217 (June 10, 1999). We found the conformity emission budget (298.6 tons per day, or tpd) in the 1995 CO plan inadequate since the area failed to meet attainment by the required date for moderate nonattainment areas and was subsequently reclassified to ''serious.''

In today's action, we are proposing to approve several control measures derived from those cited in the 1995 CO plan, including the State's wintertime RVP regulation for gasoline sold in Clark County, into the Nevada SIP. In addition, we are proposing to approve Nevada's vehicle I/M program, which now includes training and certification requirements for vehicle I/M repair technicians and which now requires annual inspection of heavy-duty gasoline-powered vehicles.

One of the individual SIP elements submitted in the 1992 to 1994 timeframe referred to above was the vehicle I/M program. Under a letter dated July 28, 1994, NDEP submitted a SIP revision related to the State's vehicle I/M program, and we determined that submittal to be complete on January 31, 1995. In the wake of changes to our requirements for such programs, NDEP submitted another SIP revision related to the vehicle I/M program under a letter dated March 20, 1996. This 1996 vehicle I/M submittal superceded the 1994 vehicle I/M submittal and was deemed complete by operation of law on September 20, 1996. Subsequent revisions of the I/M regulations were submitted in August 2000 as part of the 2000 CO plan, described below, and in 2002, the State submitted additional adopted revisions to the I/M regulations, a draft revision to the I/M provisions related to inspection of model year 1996 and newer vehicles, and supplemental materials related to vehicle roadside remote sensing (on-road testing). In today's action, we are proposing to approve the 1996 vehicle I/M program submittal as revised to reflect the changes in that program through 2002.

As noted above, the ''serious area'' CO SIP revision was due 18 months from the effective date (*i.e.*, November 3, 1997) of reclassification to ''serious,'' or May 3, 1999. By that date, Nevada had not submitted the required SIP revision, and on September 10, 1999, we published a **Federal Register** notice finalizing a finding of failure to submit a ''serious area'' SIP revision for CO. See 64 FR 49084 (September 10, 1999). This finding, which was effective on August 31, 1999, triggered an 18-month time clock for sanctions and a 2-year time clock for a federal implementation plan (FIP) under the Act.

Subsequently, under a letter dated September 29, 1999, NDEP submitted the ''Carbon Monoxide Air Quality Implementation Plan—September 1999.'' This plan, referred to herein as the 1999 CO plan, was adopted by the Clark County Board of Commissioners on September 21, 1999 and was developed to respond to the CO serious area requirements. On January 12, 2000, we sent a letter to John Schlegel, Director of the Clark County Department of Comprehensive Planning (CCDCP), summarizing problems with the plan and stating the we had made an inadequacy finding on the emission budgets in the plan, and in February of 2000, we published an inadequacy notice on conformity budgets contained in the 1999 CO plan. See 65 FR 4965 (February 2, 2000). The budgets in that CO plan were found inadequate because we determined that the measures contained in the 1999 CO plan would not be sufficient to reach attainment. Since the 1999 CO plan was superceded by the 2000 CO plan discussed below, we will be taking no action on that plan.

Under a letter dated August 9, 2000, NDEP submitted the 2000 CO plan for Las Vegas Valley, adopted by the Clark County Board of Commissioners on August 1, 2000 (referred to herein as the 2000 CO plan). We determined this submittal to be complete on September 12, 2000, with respect to portions of the plan relating to CO SIP requirements.[4] On November 20, 2000, we also found that the motor vehicle emission budgets in the 2000 CO plan were adequate for transportation purposes.

In June 2001, the Governor of Nevada designated the Clark County Board of Commissioners as the regulatory, enforcement and permitting authority for implementing the Federal Clean Air Act within Clark County. This action by the Governor necessitated a transfer of certain pre-existing authorities from the Clark County Board of Health to the County Board of Commissioners. In response to the Governor's designation, the Clark County Board of Commissioners created the Clark County Air Quality Management Board (CCAQMB) as the governing agency for air quality programs and regulations in Clark County. CCAQMB acts through a new County department, referred to as the Clark County Department of Air Quality Management (CCDAQM), which has assumed the responsibilities for air quality enforcement functions that had been performed by the Clark County Health District as well as for air quality planning functions previously performed by CCDCP.

Lastly, under letters dated January 30, 2002 and June 4, 2002, NDEP submitted additional information to supplement the 2000 CO plan, including, among other items, current versions of certain adopted I/M and fuel regulations, a draft version of revised I/M regulations and a request that EPA ''parallel process''[5] these draft regulations as part of our proposed action on the 2000 CO plan, and the current statutory authority for the I/M program in Las Vegas Valley. In today's action, we are proposing to approve the plan elements and measures contained in this 2000 CO plan as supplemented by the materials submitted by NDEP in January and June 2002.

E. What Is Included in the 2000 Las Vegas Valley CO Plan?

This 2000 CO plan provides, among other things, a revised CO attainment demonstration based on updated vehicle miles traveled (VMT) projections reflecting new forecasts prepared by the Clark County Regional Transportation Commission (RTC), revised motor vehicle emission modeling, new emissions inventories, amended control measures, and updated areawide Urban Airshed Modeling (UAM) and hotspot (CAL3QHC) air quality modeling analyses using the updated inventories and improvements to other modeling inputs.

II. EPA Action

A. What Is EPA Proposing To Approve?

In this document, we are proposing to approve the 2000 CO plan, with respect to the CAA requirements for notice and adoption, baseline and projected emissions inventory, the reasonable

[4] EPA adopted the completeness criteria on February 16, 1990 (55 FR 5830) and, pursuant to section 110(k)(1)(A) of the Act, revised the criteria on August 26, 1991 (56 FR 42216).

[5] Under the ''parallel processing'' procedure, EPA proposes rulemaking action concurrently with the state's procedures for approving a SIP submittal and amending its regulations (40 CFR part 51, appendix V, 2.3). If a state's proposed revision is substantially changed in areas other than those identified in this document, EPA will evaluate those changes and may publish another notice of proposed rulemaking. If no substantial changes are made, EPA will publish a final rulemaking on the revisions after responding to any submitted comments. Final rulemaking action by EPA will occur only after the SIP revision has been fully adopted by the state and submitted formally to EPA for incorporation into the SIP.

further progress (RFP) demonstration, the attainment demonstration, and VMT forecasts. In addition, we are proposing to approve Nevada's low enhanced I/M program for Clark County under section 187(a)(6) of the Act, Clark County's wintertime Cleaner Burning Gasoline program under section 211(c)(4)(C) of the Act, and Nevada's wintertime gasoline specification for Clark County related to Reid Vapor Pressure (RVP). These three programs, along with previously-approved oxygenated fuel regulations and natural vehicle turnover (replacement of older higher-emitting vehicles with newer models manufactured to meet increasingly stringent emissions standards), are the main control programs relied upon to reach attainment. We are also proposing to approve an alternative fuel program for government vehicles, voluntary transportation control measures, a determination that stationary sources do not contribute significantly to CO levels for the purposes of section 187(c) of the Act, a contingency measure, commitments for further submittals and control measures, as needed, and CO emissions budgets for conformity purposes.

B. Does the 2000 CO Plan Meet All the Procedural Requirements?

As noted in our earlier completeness finding for the 2000 CO plan (letter dated September 12, 2000 from Amy Zimpfer to Allen Biaggi), the CCDCP has satisfied applicable statutory and regulatory requirements for reasonable public notice and hearing prior to adoption of the plan and each of the plan amendments. The CCDCP conducted numerous public workshops and public hearings prior to the adoption hearing on August 1, 2000, at which the 2000 CO plan was adopted by the Clark County Board of County Commissioners, the lead agency for local air quality planning in the Las Vegas Valley area. The SIP submittal [6] includes a description of public meetings and hearings where the public had the opportunity to comment on the issues addressed in the plan. Public noticing for these meetings occurred through advertisements in the Las Vegas Review Journal and the Las Vegas Sun as well as on the Internet. Also included are the comments received from the public and responses developed by the CCDCP staff. Therefore, we propose to approve the 2000 CO plan as meeting the procedural requirements of section 110(a)(2) of the Act.

C. What Levels of CO Are Estimated for the Base Year and Projected for Future Years and Does the Plan Provide for Reasonable Further Progress?

The revised and updated emissions inventory included in the 2000 CO plan is consistent with our guidance documents.[7] The motor vehicle emissions factors used in the plan were generated by the EPA MOBILE5 model. The base-year (1996) inventory was developed using MOBILE5a (as adjusted to account for off-cycle emissions); MOBILE5b was used for emissions projections for years 2000, 2010, and 2020 (also adjusted to account for off-cycle emissions). The gridded CO inventory for motor vehicles was then produced using the Direct Travel Impact Model version 2.0 (DTIM2), distributed by the California Department of Transportation, which combines motor vehicle emission factors with transportation modeling performed by RTC.

The point source inventory was prepared primarily from a mail survey by the Clark County Health District (CCHD). Survey results were supplemented by information obtained through personal contacts during compliance inspections. VMT data necessary to calculate on-road mobile source emissions was provided by RTC. Table 1 below contains demographic information for Clark County.

TABLE 1.—DEMOGRAPHIC DATA USED IN DEVELOPING EMISSION INVENTORIES AND TO PROJECT ACTIVITY LEVELS FOR NONATTAINMENT AREA [1]

Year	Population	Employment	VMT
1996	1,037,844	493,213	22,469,020
2000	1,269,600	609,400	24,929,485
2010	1,790,700	859,500	38,022,330
2020	2,406,500	1,115,100	57,492,333

[1] Data is based on Clark County Regional Transportation Commission (RTC) 1997 Estimates/Projections.

Base Year Emissions

The results of the Las Vegas Valley 1996 base year CO emissions inventory for stationary point and area sources, on-road mobile sources, and nonroad mobile sources categories are tabulated in this section. The biogenics category has been omitted, as it is not applicable to CO emissions. Table 2 below contains a detailed listing of average daily CO season emissions by source category. Large stationary sources at the periphery of the nonattainment area (State hydrographic area No. 212) have also been included in the inventory.

TABLE 2.—1996 CO EMISSIONS—AVERAGE DAILY CO SEASON

Source categories	Emissions (Tons/day)	Emissions (Percent)
Stationary Point Sources:		
Titanium Metals	2.84	0.60
Kerr McGee-BMI	0.24	0.05
Chemical Lime Co. Apex	0.82	0.17
Bonanza Materials	0.28	0.06

[6] A summary of public participation activities in the development of the plan are included in Appendix D, section 11 of the 2000 CO plan.

[7] *See,* for example, Emission Inventory Requirements for Carbon Monoxide State Implementation Plans, EPA—450/4–91–011; Procedures for the Preparation of Emission Inventories for Carbon Monoxide and Precursors of Ozone, Volume I: General Guidance for Stationary Sources EPA—450/4–91–016; Procedures for Emission Inventory Preparation, Volume IV: Mobile Sources, EPA 450/4–91–026d Revised.

TABLE 2.—1996 CO EMISSIONS—AVERAGE DAILY CO SEASON—Continued

Source categories	Emissions (Tons/day)	Emissions (Percent)
James Hardie Gypsum	0.55	0.12
Southern Nevada Paving	0.55	0.12
Pabco Cogeneration/NCA 2	0.55	0.12
Georgia Pacific@Apex/NCA 1	0.62	0.13
Point Source Total	6.45	1.36
Area Sources:		
Small Stationary	2.70	0.57
Boiler Emissions	1.24	0.26
Fireplaces	2.12	0.45
Structural Fires	0.87	0.18
Vehicular Fires	0.07	0.01
Brush Fires	1.68	0.36
Residential Natural Gas	0.78	0.16
Commercial Natural Gas	0.17	0.04
Industrial Natural Gas	0.36	0.08
Electrical Utility Generation	0.56	0.12
Cigarette Smoking	0.05	0.01
Area Source Total	10.59	2.24
Nonroad Mobile Sources:		
County Airports	36.4	7.69
Nellis AFB	2.86	0.60
Locomotive Emissions	0.23	0.05
Lawn and Garden Equipment	0.86	0.18
Construction Equipment	7.84	1.66
MC & Recreational Equipment	2.93	0.62
Total Nonroad Sources	51.12	10.79
On-road Mobile Sources	405.40	85.61
Total Daily Emissions	473.56	100.0

Total average daily, CO season emissions associated with the Las Vegas Valley nonattainment area for the 1996 base year are 473.56 tons per day. The methodologies used to prepare the base year emissions inventory, as described in chapter 3 and appendix A of the 2000 CO plan, are acceptable. Accordingly, we propose to approve the 2000 CO plan with respect to the base year emissions inventory requirements of sections 172(c)(3) and 187(a)(1) of the Act.

Future Year Emissions

The plan must estimate future year emission levels to determine if Las Vegas Valley can reduce CO levels to acceptable levels. Emission estimates for the year 2000 are projected using growth factors from the Bureau of Economic Analysis (for stationary, area and nonroad sources) and using projected population, employment and VMT data from RTC (for on-road sources). Levels are estimated both with and without the impact of the new control programs included in the 2000 CO plan. A summary of these emission estimates is given in Table 3.

TABLE 3.—CO EMISSIONS BY MAJOR SOURCE CATEGORY—AVERAGE DAILY EMISSIONS, CO SEASON, YEAR 2000

Source Category	Emissions (tons/day)	
	Uncontrolled	Controlled
Stationary Sources	6.45	6.45
Area Sources	12.41	12.41
On-road Vehicles	353.23	310.18
Other Mobile	53.45	53.45
Total	425.44	382.40

The decline in emissions from uncontrolled to controlled shown in Table 3, above, is attributed to the wintertime Cleaner Burning Gasoline regulation, on-road vehicle fleet turnover, the technician training and certification requirements of the State's vehicle I/M program, an alternative fuels program for government fleets and voluntary transportation control measures. Also, as described in the following section, the CO emissions reductions under the 2000 CO plan are sufficient to demonstrate attainment by the applicable date. Thus, the 2000 CO

plan includes a control strategy that has been implemented to produce annual incremental reductions of emissions and that has thereby provided for RFP toward attainment of the standard by the applicable attainment date (December 31, 2000).

In this action, therefore, we propose to approve the projected emissions inventories, under sections 172(c)(3) and 187(a)(1) of the Act, and approve the 2000 CO plan with respect to the RFP requirements in sections 172(c)(2) and 187(a)(7) of the Act.

D. How Does the CO Plan Show Attainment of the CO Standards?

The attainment demonstration includes both an areawide and a hot-spot modeling analysis at heavily-traveled intersections. The areawide analysis was conducted using the Urban Airshed Model (UAM), according to our ''Guidance for Application of Urban Areawide Models for CO Attainment Demonstrations'' (1992). The UAM analysis uses a December 8–9, 1996 episode. This episode predicted an 8-hour concentration of 11.2 ppm after all adjustments were incorporated. In addition to high 8-hour values on this day, the highest one-hour value (11.8 ppm) was also recorded on this episode day.

Emissions inventory data used in the base year (1996) UAM analysis were derived from the data shown in Table 2, above. The emissions inventory data used for the UAM analysis were disaggregated into 5 kilometer grid cells throughout the modeling domain. On-road emissions were distributed using the 1996 roadway network and emission factors. Model performance for the base year UAM simulation is within our acceptable range of accuracy: +17 percent for the unpaired peak prediction, 0 percent for the paired peak prediction, and 3 hours for the timing error. See 2000 CO plan, page 5–5.

For the attainment year (2000) and for additional future years, on-road emissions were distributed using the Direct Travel Impact Model (DTIM) with latest projected roadway networks including future transportation projects from RTC. Thus, projected changes in Vehicle Miles Traveled (VMT), speed and vehicle occupancy rates were incorporated into the modeling.

TABLE 4.—UAM RESULTS FOR CONTROLLED AND UNCONTROLLED SCENARIOS

Concentrations [ppm]

Year	Uncontrolled Scenario	Controlled Scenario
1996	11.2	11.2
2000	9.1	8.1
2010	8.7	7.2
2020	10.5	8.5

Source: 2000 CO plan, Table 6–3.

The table shows the results of the UAM analysis for the 8-hour average (the corresponding NAAQS is 9 ppm). Concentrations for the 8-hour average are shown for the maximum concentration predicted over the modeling domain. The predicted regional maximum 8-hour average CO concentration is 8.1 ppm in the year 2000, assuming implementation of all new control measures. The UAM analysis thus shows attainment with a margin of safety based on fully adopted regulations. However, an additional model, CAL3QHC must be used to determine the maximum CO levels in the area. CAL3QHC is needed to predict the micro-scale impacts of vehicles operating at congested intersections. Vehicles operating within congested conditions spend more time in idle modes that can contribute to high levels of CO near the roadways.

Microscale modeling was conducted for three intersections within Las Vegas Valley; (1) Charleston Blvd./Eastern Avenue, (2) Charleston Blvd./Fremont Street and (3) Eastern Avenue/Fremont Street. These three intersections comprise the ''5 points'' area which is near the Sunrise Acres CO monitoring station. For years 2000, 2010, and 2020, traffic data from the roadways were combined with emission factors from MOBILE5b and meteorological data to predict local hotspot concentrations. These hourly results from the microscale model were then combined with hourly concentrations from the background UAM grid cell to compute maximum running 8-hour concentrations. The combined results of the CAL3QHC and UAM results are shown in Table 5 below.

TABLE 5.—INTERSECTION MAXIMUM PREDICTED COMBINED 8-HOUR CO LEVELS (PPM)

Intersection	2000	2010	2020
Charleston/Eastern	8.3	7.3	7.6
Charleston/Fremont	6.7	5.9	6.4
Eastern/Fremont	7.6	6.6	7.4

Source: 2000 CO plan, Table 6–4.

In addition to roadway intersections, high microscale CO levels can occur at airports. To model the impact of airport sources, the Emissions and Dispersion Modeling System (EDMS) model was used. This model was developed for evaluating the specific emission sources typically located at airports. As with CAL3QHC, the hotspot results from EDMS must be combined with the results of the UAM analysis to predict the concentrations at receptors around the airports. The 2000 CO plan presents results of the combined UAM and EDMS models for the base case (uncontrolled). Even without controls, no values above the 9.0 ppm standard are shown for the attainment year (2000). The peak combined concentration at McCarran International Airport for future years is 9.07 ppm for 2020. However, with the addition of just one of the controls included in the plan (specifically, Cleaner Burning Gasoline), the predicted concentration is reduced to 7.67 ppm, well below the 8-hour standard. Therefore, we propose to grant

approval to the 2000 CO plan with respect to the attainment demonstration requirement of section 187(a)(7) of the Act.

E. How Are Motor Vehicle Emissions Reduced in Las Vegas Valley?

Motor vehicle emissions in Las Vegas Valley are reduced primarily by a combination of natural fleet turnover, which effectively replaces older higher-emitting vehicles with models manufactured to meet more stringent exhaust emissions standards established under the federal motor vehicle control program, a vehicle I/M program for in-use vehicles, and wintertime specifications for gasoline. Other measures that contribute to lower CO emissions include an alternative fuel program for government vehicles and voluntary transportation control measures. This section addresses the vehicle I/M program, and following sections address wintertime gasoline specifications and the other control measures.

Summary of the Nevada I/M Program

The State of Nevada has implemented an I/M program for vehicle emissions in Las Vegas Valley since 1978. In 1981, we approved the statutory basis for the vehicle I/M program for Las Vegas Valley. See 46 FR 21758 (April 14, 1981) and 40 CFR 52.1470(14)(iv) and (16)(vi). In 1984, we approved the regulatory basis for that program into the Nevada SIP. See 49 FR 44208 (November 5, 1984) and 40 CFR 52.1470(c)(26)(iii). Because Las Vegas Valley was designated as a moderate CO nonattainment area with a design value greater than 12.7 ppm under the 1990 CAA Amendments, the State of Nevada was required under section 187(a)(6) of the Act, as amended in 1990, to revise the vehicle I/M program within Las Vegas Valley to meet ''enhanced'' performance standards, referred to as an enhanced vehicle I/M program.

On November 5, 1992, we published rules in the **Federal Register** related to plans for vehicle I/M programs (see 57 FR 52950). The Act was prescriptive regarding the various elements that are required as part of an enhanced I/M performance standard. It also required that we provide states with flexibility in meeting the requirement for enhanced or basic I/M programs. Title 40, part 51, § 51.351(g) Alternate Low Enhanced I/M Performance Standard in the Code of Federal Regulations (40 CFR 51.351(g)) allows states that meet certain specific criteria to select the alternate ''low'' enhanced I/M performance standard instead of the ''high'' enhanced performance standards. We established an alternate low enhanced I/M performance standard for those areas that are required to implement enhanced I/M but do not have a major mobile source component to the air quality problem or can obtain adequate emission reductions from other sources to demonstrate RFP and attainment.

The State of Nevada chose to adopt a low enhanced vehicle I/M program and submitted this program to us as a SIP revision on March 20, 1996. The 1996 SIP Submittal for Nevada's vehicle I/M program supercedes and builds upon the ''basic'' program that we approved in 1984.

The 1996 SIP Submittal contained an overview of the State's I/M program, a checklist/review of the plan relating it to our requirements, legislation, rules, implementation of the program, MOBILE5a analysis (the 2000 CO plan included a revised analysis of the I/M program based on MOBILE5b), motor vehicle fleet characteristics, and numerous other appendices containing material describing the program.

The State Environmental Commission (SEC) and the Department of Motor Vehicles and Public Safety (DMV&PS), which was the predecessor agency to today's DMV and Department of Public Safety, revised the I/M regulations in 1996, 1998, and 2000 to, among other things, increase the cost enabling a registrant to qualify for a waiver (to $450) and exempt ''restored vehicles'' from certain provisions of the program. The 2000 CO plan included a revised emissions analysis using MOBILE5b (see appendix E, section 7 of the plan) taking into account the changes in the program through 2000, including 100% emissions credit for their technician training and certification program.

In two supplemental SIP submissions dated January 30, 2002 and June 4, 2002, NDEP submitted current versions of the statutory and regulatory authority for the low enhanced I/M program in Clark County, draft revisions to Nevada Administrative Code (''NAC'') 445B.580 relating to procedures for inspecting on-board diagnostics (OBD) systems on light-duty MY 1996 or newer vehicles (and a request that we ''parallel process'' those draft revisions), contractural materials related to emissions inspections analyzer equipment for licensed emission inspection stations, and contractual materials related to on-road testing.

The technical support document (TSD) provides an evaluation of the State's complete low enhanced vehicle I/M program relative to our requirements for such programs, including applicability; low enhanced I/M performance standard, network type and program evaluation; adequate tools and resources; test frequency and convenience; vehicle coverage, test procedures and standards; test equipment; quality control; waivers; motorist compliance enforcement; quality assurance; enforcement against contractors, stations, and inspectors; data collection; data analysis and reporting; inspector training and certification; public information and consumer protection; improving repair effectiveness; compliance with recall notices; and on-road testing.

EPA Review of the Low Enhanced SIP Revisions

EPA's requirements for basic and enhanced I/M programs are contained in 40 CFR part 51, subpart S. The SIP revisions submitted by NDEP must be consistent with these requirements and must meet EPA's requirements for enforceability, as well as, CAA section 110(l) requirements. Although the required elements under Nevada's low enhanced I/M program differ from those described in EPA's I/M requirements for low enhanced programs, a side-by-side comparison demonstrates that, overall, they are not less stringent (see discussion of emissions modeling results in subsection 8, below).

1. Network Type, Test Frequency, Exhaust Emission Test Type and Vehicle Coverage

Basic and enhanced I/M programs can be centralized (i.e., state-run or a single contractor), decentralized (i.e., private small businesses), or a hybrid of the two, but the network type selected by a given state together with the other elements of the state I/M program must achieve the same or better level of emission reduction as the applicable performance standard. The low enhanced I/M performance standard assumes annual testing through a centralized testing network of all model year (MY) 1968 and newer light duty vehicles and light duty trucks, rated up to a gross vehicle weight rating (GVWR) of 8,500 pounds. The low enhanced I/M performance standard assumes that the exhaust emissions of the subject vehicles are subject to the idle test.

The current low enhanced vehicle I/M program for Las Vegas Valley and Boulder City requires two speed idle testing of all light-duty gasoline-powered vehicles MY 1968 through 1995, and for all heavy-duty gasoline-powered vehicles MY 1968 and newer on an annual basis. Until recently, light-duty gasoline-powered vehicles MY 1996 and newer were also subject to two speed idle testing; but recent changes in the State I/M program now require that

such vehicles be tested via on-board diagnostic systems checks instead of the two speed idle test. For the State I/M program, ''light-duty vehicles'' refers to passenger cars and trucks up to 8,500 pounds GVWR; ''heavy-duty vehicles'' refers to trucks which have a GVWR of 8,500 pounds or more. The network is decentralized and includes both test-and-repair and test-only stations. All 304 stations are privately owned stations, 96 of which are test-only stations.

2. Exhaust Standards for CO and Hydrocarbons (HC)

Standards for exhaust emission testing are specified in 40 CFR part 85, subpart W. Consistent with those standards, the State I/M program establishes, for those vehicles that are subject to emissions testing, maximum exhaust emissions for MY 1981 and newer vehicles of 1.2% for CO and 220 ppm for HC. For older light-duty vehicles (MY 1968 through 1980), maximum CO (%) and HC (ppm) range from 4.0%–2.0% and 800 ppm–500 ppm, respectively. The standards for heavy-duty gasoline-powered trucks MY 1981 and newer are 3.5% for CO and 1000 ppm for HC; for older heavy-duty vehicles (MY 1968 through 1980), maximum CO (%) and HC (ppm) range from 7.0%–4.0% and 1,400 ppm–1,000 ppm, respectively. As stated previously, all light-duty motor vehicles MY 1996 and newer are subject to on-board diagnostic system checks.

Diesel vehicles are tested under separate requirements, and the requirements that relate to diesel vehicles are not being approved into the SIP.

3. Geographic Coverage

EPA's I/M regulations require that state I/M programs be implemented in the entire urbanized area, based on the 1990 census. See 40 CFR 51.350. The designation for the low enhanced I/M areas are the boundaries of Hydrographic Basin 212, as established by the State Engineer, and the city limits of Boulder City.

4. Vehicle Coverage

The performance standard for low enhanced I/M programs assumes coverage of all MY 1968 and later light-duty vehicles and trucks up to 8,500 pounds GVWR. Other levels of coverage may be approved if the necessary emission reductions are achieved. See 40 CFR 51.356.

As mentioned above, the Nevada low enhanced I/M program applies to light-duty, gasoline-powered vehicles up to 8,500 pounds GVWR, and heavy-duty, gasoline-powered vehicles within the CO nonattainment area of Clark County and Boulder City. While still subject to annual vehicle registration requirements, new vehicles are exempt from emissions inspections under the Nevada I/M program until the third registration cycle. Subsequent annual registration or re-registration will require proof of compliance with emission testing. Vehicles MY 1967 and older, and motorcycles are also exempt from the I/M testing. The two-year exemption of newer model year vehicles from emissions testing results in a relatively small loss in emission benefit since newer vehicles are generally anticipated to be cleaner than older vehicles. Furthermore, recent data suggest that newer vehicles stay cleaner longer due to the slower rate of emission control system deterioration.

The federal regulations also require basic and enhanced I/M programs to include inspection of all 1996 and later motor vehicles equipped with on-board diagnostic (OBD) systems. EPA has required that I/M programs begin OBD checks on January 1, 2002 (OBD mandatory start-up dates were delayed for one year). See 40 CFR 51.373. OBD consists of a computer which performs checks of a number of different vehicle systems for malfunctions or deterioration which could result in the vehicle exceeding its emissions standards and a malfunction indicator light which is required to be illuminated when the system detects a problem.

Some inspection stations in Las Vegas began OBD testing MY 1996 and newer OBD-equipped light-duty vehicles in February 2002 using the NV2000 analyzer (Nevada's previous I/M emissions analyzer, referred to as the ''Nevada 94'' analyzer, was not programmed to conduct OBD testing). By May 1, 2002, all inspection stations in Las Vegas Valley were conducting OBD tests for MY 1996 and newer OBD-equipped vehicles. Vehicles which receive an OBD inspection do not receive a two speed idle tailpipe test.

5. Emission Control Device Inspections

The low enhanced I/M performance standard assumes visual inspection of the positive crankcase ventilation valve on all 1968 through 1971 MY vehicles, inclusive, and of the exhaust gas recirculation valve on all 1972 and newer MY vehicles. Nevada's program requires visual inspection of the presence of a properly installed gas cap on all gasoline-powered vehicles MY 1968 through 1980, and on heavy-duty gasoline-powered MY 1968 and newer. For light-duty, gasoline-powered vehicles MY 1981 through 1995 vehicles visual inspections include: (1) Determining the presence of an exhaust gas recirculation valve, (2) examining the catalytic converter, air injection system and fuel inlet restricter; and (3) determining whether that equipment appears to be operating in accordance with the specifications of the manufacturer of the vehicle.

6. On-Road Testing

EPA regulations require on-road testing in enhanced I/M programs; on-road testing is optional for basic I/M programs. The on-road testing requirement may be met by measuring on-road emissions through the use of remote sensing devices or through roadside pullovers including tailpipe or evaporative emission testing or a check of the OBD system. The federal regulations require on-road testing to evaluate annually the emission performance of 0.5% of the subject fleet statewide or 20,000 vehicles, whichever is less, per inspection cycle. See 40 CFR 51.371.

Nevada's legal authority for on-road testing was adopted by its Legislature in Senate Bill 570, which was signed into law by the Governor on July 5, 1995. This legislation added a new section to Chapter 445B of the Nevada Revised Statutes (NRS) providing authority to implement a remote sensing program as part of the vehicle I/M program (*i.e.*, NRS 445B.798). In the June 2002 SIP Submittal, Nevada submitted a copy of the executed contract between the State and MD Laser Tech for on-road testing services, effective through June 30, 2003. DMV has contracted with MCI Worldcom to develop and maintain the vehicle information emission database (VID). The MCI Worldcom VID communicates with the DMV registration database. All emission test results are transmitted from the vehicle information emission database to the DMV's registration database. The MCI Worldcom system (VID) also maintains the licensee and administrative programs which are used to identify emission stations and produce program statistical reports. On-road testing is located in the administrative program which can be used to store statistical records for vehicles tested through this process. Letters can also be generated to vehicle owners when regulatory action is determined to be proper. The MD Laser Tech contract calls for the contractor to perform remote sensing of motor vehicle exhaust emissions for a specified time period at specified locations within Clark County. The primary operational objective is to obtain information concerning gross emitting vehicles and use this

information to ensure that these vehicles are brought into compliance with Nevada's motor vehicle regulations. Failure of a test conducted under the on-road testing program may lead to cancellation of vehicle registration under NRS 482.461 unless, within the prescribed period, the registered owner has the vehicle inspected and repaired (if necessary) and provides the DMV with evidence of compliance with the I/M requirements.

7. Waivers

EPA's requirements allow I/M programs to provide a waiver which lets the motorist comply with the program without meeting applicable test standards so long as certain prescribed criteria are met. See 40 CFR 51.360. In basic programs, a minimum of $75 for pre-1981 vehicles and $200 for 1981 and newer vehicles must be spent by the motorist for appropriate repairs in order to qualify for a waiver. See 40 CFR 51.360(a)(6). Beginning January 1, 1998, enhanced programs must require motorists to spend at least $450 for appropriate repairs. See 40 CFR 51.360(a)(7).

Nevada's I/M regulations (NAC 445B.590) require at least $450 in expenditures on emissions-related vehicle repairs to qualify for a waiver in Clark County. Only the DMV may grant a waiver from the standards for emissions. Nevada's rules provide that a waiver from the applicable standards may only be issued after a retest is failed after qualifying repairs. The number of failed vehicles that require waivers is not expected to exceed the current waiver rate of approximately 1 percent. If the waiver rate exceeds 1 percent, Nevada will re-evaluate their procedures. EPA's model waiver rate is a 3 percent waiver rate, as a percentage of failed vehicles. Under the State's program, waivers are denied if the parts have not been installed or the repairs have not been performed as indicated on the receipts. A waiver applies for only the one year vehicle registration period. If a vehicle were to fail the next year, the procedure must be performed again.

8. Low Enhanced I/M Performance Standard

EPA's I/M regulations require that the state perform modeling using the most current version of EPA's mobile source emissions model to determine that the emissions levels achieved by the state I/M program meet the minimum performance standard. See 40 CFR 51.351(g). The minimum performance standard reflects the ''model program'' elements list in 40 CFR 52.351(g) (*e.g.* centralized annual testing of light-duty vehicles and trucks up to 8,500 GVWR MY 1968 and newer).

For the 2000 CO plan, Clark County updated the emissions analysis of the Nevada I/M program design using MOBILE5b. (The 1996 I/M SIP submittal included emissions analysis based on MOBILE5a.) The Nevada vehicle I/M program design includes: computerized test and repair (50% default values were used to discount emissions reduction benefits of Nevada's largely test-and-repair network relative to a test-only network); 1983 start date; 1999 last model year covered (reflects the first two years exemption on new vehicles and a model run for calendar year 2002); annual frequency; 1968 and newer model year coverage; vehicle types include light duty gasoline-powered autos and trucks (LDGV, LDGT1, and LDGT2) and heavy-duty gasoline-powered vehicles (HDGV); five-element visual inspection and gas cap check on all vehicles MY 1981 and newer; stringency rate for pre-1981 vehicles of 20 percent; waiver rate of 1 percent; a 96 percent compliance rate; and 100 percent emissions credit for the State's technician training and certification program.

The emissions evaluation of the State's I/M program reflects two speed idle testing for all subject vehicles. Given an analysis year of 2002 and the State's two-year exemption for new vehicles, the emissions evaluation reflects two speed idle testing for all subject vehicles MY 1968 through MY 1999. The additional emissions reductions associated with OBD checks were not included in the emissions evaluation of the State's program or in the emissions evaluation of the low enhanced I/M performance standard with which the State's program is compared. (Recent changes in the State program now require OBD checks for subject vehicles MY 1996 and newer instead of the two speed idle test).

Section 7 of appendix E of the 2000 CO plan includes the input and output files from MOBILE5b. As shown in these files, the composite CO emissions factor for January 1, 2002 under the State's program (15.18 grams per mile) is below the corresponding emission level target (15.49 grams per mile) that reflects the EPA model program; and thus, the State's low enhanced I/M program for Las Vegas Valley and Boulder City meets the EPA performance standard for CO.

9. Legal Authority for the Program

The federal I/M rule requires that a state I/M SIP submittal cover the legal authority requiring or allowing implementation of the I/M program and providing either broad or specific authority to perform all required elements of the program as well as implementing regulations, interagency agreements, and memoranda of understanding. See 40 CFR 51.372(a)(5) and (7). Nevada's 1996 I/M SIP submittal included the legal authority and implementing regulations for the low enhanced vehicle I/M program in Las Vegas Valley and Boulder City. The 2000 CO plan, submitted as a SIP revision in 2000, and the two supplemental SIP submittals in 2002 provided updated statutes and regulations for this State program.

The legal authority for the program is vested in the Nevada SEC under Title 40 (Public Health & Safety) of the Nevada Revised Statutes (NRS), section 445B.210 and sections 445B.700 through 445B.845, and in the DMV under Title 43 (Public Safety; Vehicles; Watercraft) of NRS, sections 481.047–481.083, 482.155–482.283, 482.385, 482.461, 482.565, and 484.644–484.6441. The implementing regulations are found at Nevada Administrative Code (NAC) 445B.400 through 445B.735.

The federal I/M rule requires the state I/M program to remain in operation until it is no longer necessary. See 40 CFR 51.372(a)(6). Nevada's I/M program does not undergo a sunset review. We believe that NDEP has demonstrated that the Nevada I/M programs will remain in operation as long as necessary and the requirements of 40 CFR 51.372 have been satisfied.

Conclusion and Proposed Approval of I/M program

We conclude, based on our review of the vehicle I/M program relative to our requirements and within the context of the 2000 CO plan, that the 1996 SIP Submittal for the low enhanced vehicle I/M program, as revised and supplemented through 2002, meets our requirements and contributes to the demonstration of attainment of the CO NAAQS by the applicable date. We, therefore, propose to approve the vehicle I/M program for Las Vegas Valley and Boulder City into the Nevada SIP. Specifically, we propose to approve the statutory and regulatory basis for the revised program in NRS, title 40, section 445B.210 and sections 445B.700 through 445B.845, and title 43, sections 481.047–481.083, 482.155–482.283, 482.385, 482.461, 482.565, and 484.644–484.6441, as amended by Nevada through 2001, and NAC sections 445B.400 through 445B.735 (not including 445B.576, 445B.577, and 445B.578), as adopted through March 8,

2002, by SEC and DMV, and, in the case of draft revisions to NAC 445B.580 Inspection of vehicle: Procedure (NRS 445B.785), as submitted by NDEP by letter dated January 30, 2002. We will consider final action on the vehicle I/M program once we receive the final adopted version of NAC 445B.580. (This section includes final test procedures and equipment used for inspecting certified OBD systems. A new section number will replace NAC 445B.580.) Our approval of the statutory and regulatory basis for the revised vehicle low enhanced I/M program would supercede the existing statutory and regulatory basis for vehicle I/M in the Nevada SIP (as approved by EPA in 1981 and 1984) as it relates to Las Vegas Valley.

F. Are Any Special Fuels Used in Motor Vehicles Operated in Las Vegas Valley?

Wintertime gasoline specifications in Clark County reduce CO emissions in Las Vegas Valley. Specifically, these wintertime specifications relate to oxygen, Reid Vapor Pressure (RVP), sulfur content and aromatic hydrocarbons (''aromatics''). In a separate, prior action, we approved the wintertime oxygenated fuels regulation in Clark County under sections 187(b)(3) and 211(m) of the Act. See 64 FR 29573 (June 2, 1999). The low RVP wintertime gasoline regulation was submitted as part of the 1995 CO plan and the most recent version of that regulation was submitted to EPA on June 4, 2002. EPA is proposing to approve that regulation into the Nevada SIP in this notice, as discussed below. The wintertime sulfur and aromatics specifications are contained in Clark County's Cleaner Burning Gasoline regulation, which has been submitted as an additional control measure in the 2000 CO plan and which is discussed following the low RVP wintertime gasoline discussion.

Low RVP Wintertime Gasoline

RVP is a measure of the stabilized pressure exerted by a volume of liquid at 100° F, and is generally used as a measure of the volatility of gasoline fuel. Fuels with high RVP values volatilize more readily than fuels with low RVP values. The effect of the increased rate of volatilization at any given RVP value is largely dependent on ambient temperature. Lowering the RVP specification of gasoline reduces CO emissions from vehicles equipped with functional evaporative control systems (*e.g.*, on-board carbon-canister). The evaporative control systems adsorb gasoline vapors which are then desorbed into the vehicle's fuel intake system causing enrichment of the fuel mixture and an increase in CO exhaust emissions. A lower volatility gasoline decreases the amount of vapors adsorbed by carbon canisters which in turn lowers subsequent fuel mixture enrichment and CO exhaust emissions. Newer vehicles operate ''closed-loop,'' using oxygen sensors and constantly adjusting the air/fuel ratio. Such vehicles, which represent virtually all 1990 and later cars, are programmed to make adjustments to avoid undue enrichment (and associated emission increases) during canister purge. As a result, the effect of lower RVP on CO emissions on average will be larger for open-loop than for closed-loop cars, but there is considerable variation among manufacturers, models and model years.

The Nevada legislature granted authority to adopt regulations relating to fuel standards to the State Board of Agriculture through NRS chapter 590, section 590.070. Nevada Board of Agriculture's wintertime RVP regulations are found in chapter 590, section 590.065 of the Nevada Administrative Code (''NAC 590.065''). The specific regulation that was submitted as a control measure in the 1995 CO plan was adopted by the Board of Agriculture on September 21, 1995. Since that date, this regulation has been revised several times, *e.g.* to modify the applicable wintertime period, most recently on October 28, 1998. The current regulation, NAC 590.065 paragraphs (3) and (4), limits the RVP of gasoline sold in Clark County during the winter season (October 1 through March 31) to 9.0 pounds per square inch (psi) with no allowance for ethanol blended fuel. NDEP submitted the current adopted regulation to us for incorporation into the SIP under a letter dated June 4, 2002.

The wintertime low RVP requirement is enforced through random sampling and testing conducted by the Nevada Department of Agriculture. Funding for enforcement and monitoring activities associated with the RVP requirement is provided through a portion of the annual vehicle emission testing certificate fee.

To evaluate the effects of RVP on exhaust emissions, state and local air agencies use our MOBILE model. CCDCP used MOBILE5a to evaluate the CO emissions benefits of low RVP under wintertime conditions for the 1995 CO plan. At the time of the 1995 CO plan, the supporting documentation indicated that CCDCP properly modeled RVP controls using appropriate temperatures. However, members of the Western States Petroleum Association (WSPA) objected to the 1995 CO plan's conclusion that gasoline with higher RVP results in higher CO emissions, especially during vehicle startup. They asserted that MOBILE5a overestimated the benefit of reducing RVP and expressed their concern over the related emission reduction predictions contained in the plan.

To address these concerns, CCHD commissioned a study of vehicle emissions to assess the validity of MOBILE5a results. Because of the unusual meteorological conditions in Las Vegas Valley that are associated with historic CO exceedances, and the relative lack of data within the MOBILE5a model for evaluating the RVP effects on CO emissions under colder temperatures, the study called for a shift in the normal series of events specified by the Federal Test Procedure for vehicle certification to simulate the effect of a diurnal temperature profile accompanied by a morning and evening commute.

This study culminated in the publication of the Society of Automotive Engineers' (SAE971726), Effects of RVP Reduction on Vehicle CO Emissions During Las Vegas and Los Angeles Winter Conditions—Petroleum Environmental Research Forum Project Number 95–06 in May 1997. As part of this study, two fleets of vehicles were emissions-tested to determine the effect of gasoline RVP reductions on tailpipe CO emissions in Las Vegas and Los Angeles under conditions typical of winter CO exceedances. The analyses had two locations and two RVP's (9 and 12 psi), including separate sets of temperature ranges, base gasoline types, and oxygenate types and levels. The conclusion was that RVP reduction is a significant control measure for reducing CO emissions under conditions typical of CO exceedances in Las Vegas and Los Angeles. It was estimated that reducing RVP by 3 psi (from 12 psi to 9 psi) would reduce winter CO emissions by 12% in Las Vegas and between 0 and .8% in Los Angeles.

As part of our decision whether to approve the State's low RVP wintertime gasoline regulation into the Nevada SIP, we also must consider whether the fuel specification in that regulation is preempted under the Act. Under section 211(c)(4)(A) of the Act preempts certain state fuel regulations by prohibiting a state from prescribing or attempting to enforce ''any control or prohibition respecting any characteristic or component of a fuel or fuel additive'' for the purposes of motor vehicle emission control, if EPA has prescribed under section 211(c)(1), ''a control or prohibition applicable to such characteristic or component of the fuel or fuel additive,'' unless the state

prohibition is identical to the prohibition or control prescribed by EPA. The Federal controls on RVP, promulgated under section 211(h) and section 211(c)(1), apply only in the summer months. There is no Federal RVP control applicable to gasoline in the wintertime, and thus no Federal preemption of the State's wintertime low RVP requirement.

Therefore, we are proposing to approve the State's wintertime low RVP requirement into the Nevada SIP as a CO control measure [*i.e.*, NAC 590.065, as adopted on October 28, 1998] because the State has demonstrated that the measure is enforceable, contributes to the attainment demonstration by reducing vehicular CO emissions in the Las Vegas Valley nonattainment area, and is not preempted under section 211(c)(4) of the Act. The TSD provides a copy of the State's low RVP wintertime regulation and additional information on the emissions effects of the regulation.

Cleaner Burning Gasoline

The Clark County Board of Health, which governs the CCHD, adopted a wintertime Cleaner Burning Gasoline (CBG) regulation in 1999 that results in lower CO emissions from motor vehicles. The CBG regulation was included as one of the principal additional control measures included in the 2000 CO plan. The CBG regulation requires that gasoline sold in Clark County comply with limits on the maximum levels of sulfur and aromatics during the period from November 1 to March 31.

As noted previously, the air-quality-related regulatory authority that had been vested in the County Board of Health was transferred to the County Board of Commissioners in 2001. On July 24, 2001, the Clark County Board of Commissioners adopted County ordinance #2627, which, among other items, adopted the Board of Health's air quality regulations then in effect, including the CBG regulation, except for substitutions in the references to the applicable agency (*e.g.*, ''Clark County Air Quality Management Board'' was substituted for ''Clark County District Board of Health''). We have not yet received CCAQMB's wintertime CBG regulation (*i.e.*, CCDAQM regulation, section 54) from NDEP as a SIP submittal, but are proposing approval of the CCAQMB's CBG rule at this time based on the condition that the State submit to EPA the CCAQMB version of the rule prior to our taking final action. In so doing, and as discussed more fully below, we are proposing approval of CCAQMB's CBG rule based on the substance of the Board of Health's CBG regulation and our review of the analysis of that regulation contained in the 2000 CO plan because the two versions of the CBG rule are the same (but for the substitution in agency references as noted above).

The Board of Health's CBG regulation (CCHD regulation, section 54) and the related technical support document are in appendix D, section one, of the 2000 CO plan. The regulation includes sections on: Definitions; applicability of the standards; the standards for sulfur content and aromatics content; sampling, testing and recordkeeping; requirements pertaining to CBG blendstock for oxygenated blending and downstream blending; and enforcement.

The CBG regulation provides two alternative ways to be in compliance for the specifications on sulfur and aromatics: (1) marketers can meet a flat limit on a per gallon basis or (2) marketers can comply via averaging, with each per gallon sample not to exceed a certain cap. (The CBG rule does not change current State and local regulations for wintertime RVP (9 psi) and minimum oxygen content (3.5%).) A summary of the limitations is shown in Table 6.

TABLE 6.—SPECIFICATIONS FOR AROMATICS AND SULFUR IN CLARK COUNTY CBG

	Compliance Method I	Compliance Method II	
	Flat Limit	Average	Cap
Sulfur, ppm	40	30	80
Aromatics, percent	25	22	30

As noted above, the CBG regulation establishes gasoline standards for sulfur and aromatics, and as noted above in connection with low RVP gasoline, under section 211(c)(4) of the Act, states are preempted from prescribing any control or prohibition respecting any characteristic or component of a fuel, where there is a nonidentical Federal control or prohibition applicable to such characteristic or component. See section 5 of the TSD for further discussion of this prohibition and EPA's guidance on approval of a state fuel measure under section 211(c)(4)(C).

Our analysis of preemption of the CBG regulation addresses the specifications for sulfur and aromatics. To determine whether a state fuel requirement is preempted by a federal requirement, we compare the applicable federal fuel requirements in the area with the proposed state fuel requirements. For the purposes of this analysis, the federal fuel requirement in the Las Vegas Valley CO nonattainment area is federal conventional gasoline.

In this proposed rulemaking, EPA does not need to determine whether the federal requirements for conventional gasoline include requirements for sulfur and aromatics which would preempt the CBG regulation under section 211(c)(4)(A). If the sulfur and aromatics requirements are not preempted, there is no bar to our approving them as a SIP revision.[8] If they are preempted, we may approve the CBG regulation as necessary under section 211(c)(4)(C) if we could approve each of these requirements as a SIP revision, *i.e.*, if CCHD's documentation for the regulation shows that each requirement (*i.e.*, the sulfur limit and the aromatics limit) is ''necessary'' to achieve the CO NAAQS.

Sulfur and aromatics specifications both reduce CO emissions. Emissions modeling data shows that each of these controls, independently, contributes to CO emissions reductions. Thus, each requirement can be determined ''necessary'' to achieve the CO NAAQS if the remaining requirements of the necessity determination are met.

To make a necessity determination, we must consider whether there are other reasonable and practicable measures available that would produce sufficient emissions reductions to attain the CO NAAQS without implementation of the CBG requirements. Section 211(c)(4) is intended to ensure that a state resorts to a fuel measure only if there are no available practicable and

[8] It is clear, however, that as of December 21, 1999, EPA has prescribed specific limits on maximum sulfur content in conventional gasoline. See, Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, 65 FR 6698, 6765 (February 10, 2000).

reasonable non-fuel measures. In demonstrating that measures other than sulfur and aromatics requirements for wintertime CBG are unreasonable or impracticable, a state need not address the reasonableness or practicability of other state fuel measures.

CCHD conducted an extensive public process to evaluate possible future emissions control options, including revisions to the current I/M program. CCHD considered eight control options other than wintertime CBG requirements for sulfur and aromatics. These options were: (1) Separation of test and repair stations to make its I/M program a ''high'' enhanced program, (2) creation of one-way streets, (3) adding powerful air propellers to certain developments, (4) adding 600 non-conventional-fueled buses to its municipal fleet, (5) transportation control measures, (6) alternative fuels requirements for municipal fleets, (7) lower smog cutpoints for the I/M program, and (8) episodic woodburning control. The first four options were rejected as unreasonable or impracticable due to unavailability and/or ineffectiveness.

The remaining four control measures were subject to further evaluation, but none of these measures provides significant emissions reductions. CCHD's modeling calculations show that, even with emissions reductions attributed to these four remaining measures, the CO design value would not reach 9.0 ppm by the end of 2000 without adding the reductions due to sulfur and aromatics controls for wintertime CBG.

Estimates prepared for the 2000 CO plan indicate that implementation of the CBG regulation would reduce CO emissions by 31.9 tons per day and 53.96 tons per day in years 2000 and 2020, respectively. These estimates are based on use of the Complex model (with CO added), (''CO Complex model''), in combination with the MOBILE5b model to show the emissions effects that are directly related to the specific fuel specifications in the CBG regulation. (See appendix E, section 1, of the 2000 CO plan.) In March of 1999, EPA reviewed and approved the use of the CO Complex model for CO SIP development purposes, due to the unique fuel program in use in Clark County and the inability of MOBILE5b to fully assess the impact of all of the fuel parameters. At that time, the CO Complex model was the best approach available to assess these fuel parameters.

The CO Complex model was approved for SIP development purposes in a letter dated March 23, 1999 from Roxanne Johnson, EPA Region 9, to Michael Naylor, Director, Air Pollution Control Division, CCHD.

All future transportation conformity determinations for CO in Clark County must be based on the CO Complex model with MOBILE5b until the grace period for MOBILE6 has concluded. Because MOBILE6 is not capable of estimating the benefits of this exact fuels program, EPA will work with Clark County prior to the end of the MOBILE6 conformity grace period to determine how the benefits of this program should be estimated.

Results from the modeling demonstration showed that, by implementing the wintertime CBG regulation, along with the other measures identified in the CO attainment SIP, the Las Vegas Valley should achieve the 8-hour CO NAAQS of 9 ppm by the December 31, 2000 attainment deadline.

Although CCHD did not identify the estimated quantity of CO emissions that must be reduced in order to achieve the CO NAAQS, it did estimate the CO emissions reductions attributable to each of the individual control measures (including the CBG regulation) that were subject to further evaluation. CCHD's modeling calculations showed that, without the emissions reductions attributable to the CBG regulation, Las Vegas Valley would not achieve the CO NAAQS by the end of the year 2000. Therefore, the emission reductions from the CBG regulation are necessary to achieve the CO NAAQS.

In general, to be approved as part of a SIP, regulations must include adequate enforceability provisions, such as clear indications of what constitutes a violation, who is liable, and what defenses are available. Under the CBG regulation, those who fail to comply with the CBG regulation are subject to enforcement action and may be assessed penalties of up to $10,000 per day per section violated. CCDAQM has adopted the requirements developed by CCHD for every entity in the gasoline distribution system to ensure that Las Vegas Valley will receive gasoline that meets the wintertime CBG standards. The requirements, which include registration of gasoline suppliers, testing and sampling, compliance surveys, and record keeping and reporting, apply to any producer, importer, terminal, pipeline operator, trucker, rail carrier, or retailer.

The requirements imposed by the wintertime CBG regulation apply to activity occurring both within and outside of Clark County and the State of Nevada. CCDAQM has been assigned the rights and duties of an agreement between CCHD and the California Air Resources Board (CARB) to have CARB sample and test CBG at the refineries in Southern California.

Clark County also made an agreement with the Nevada Department of Agriculture to check fuel at the final destination (*i.e.*, Clark County). The Department of Agriculture agreed to check sulfur and aromatics content of CBG fuel along with their normal testing. They would notify the CCDAQM in the event that any sample exhibits non-compliant CBG characteristics.

We have evaluated the wintertime CBG regulation and have determined that it is consistent with section 110 of the CAA and EPA regulations. We have also found that the various wintertime CBG requirements are necessary for the Las Vegas Valley nonattainment area to achieve the CO NAAQS, pursuant to section 211(c)(4)(C) of the Act. Therefore, based on the substance of the submitted Board of Health wintertime CBG regulation, and the County ordinance adopting the CBG regulation as in effect in mid-2001 (except for changes to agency references), we are proposing to approve the CCAQMB's wintertime CBG regulation (*i.e.*, CCDAQM regulation, section 54) into the Nevada SIP for the Las Vegas Valley CO nonattainment area based on the condition that the State submit to EPA the CCAQMB version of the rule prior to our taking final action.

G. Are There Any Other Programs That Reduce Overall Motor Vehicle Emissions in Las Vegas?

The 2000 CO plan includes two additional programs to reduce overall emissions of motor vehicles. These programs are a Transportation Control Measure/Transportation Demand Measure (''TCM/TDM'') program and an alternative fuel program for government fleets.

TCM/TDM Program

Section 187(b)(2) of the Act requires states with serious CO nonattainment areas to submit a SIP revision that includes transportation control strategies and measures to offset any growth in emissions due to growth in vehicle miles traveled (VMT) or vehicle trips. In developing such strategies, a state must consider measures specified in section 108(f) of the Act and choose from among and implement such measures as necessary to demonstrate attainment with the NAAQS.

Transportation control measures (''TCMs'') are designed to reduce mobile pollutant emissions by either improving transportation efficiency or reducing single-occupant vehicle trips. TCMs can

be divided into two general strategies: Transportation System Management (TSM) and Transportation Demand Management (TDM). The former is intended to improve efficiency of existing transportation infrastructure such as optimized use of capacity and improved speeds to reduce travel time delays, and the latter is intended to reduce the number of single-occupant vehicles on roadways by shifting people from single-occupant vehicles to transit and high-occupancy vehicles. In the process of preparing the 2000 CO plan, Clark County commissioned a study to estimate the CO reductions due to various individual TCMs and packages of TCMs and to identify those TCMs that showed the greatest potential for reducing CO emissions in the Valley.

The findings and recommendations of this TCM study led to the development by RTC of the CAT MATCH commuter services program, which is a voluntary TDM program that includes employer-based commuter incentive programs, telecommuting incentives and area-wide ridesharing programs. On June 10, 1999, RTC adopted Resolution No. 177, which establishes guidelines for administering the CAT MATCH commuter services program. Portions of the CAT MATCH program became operational in July 1999. Also, in connection with the CAT MATCH program, RTC adopted Resolution No. 186 (on June 8, 2000), which commits that agency to implement the CAT MATCH program, monitor participation levels, prepare annual reports comparing actual participation levels with projected levels, and remedy any shortfall of CO emission reductions resulting from actual participation levels being lower than predicted levels.

The CAT MATCH program was included as an additional control measure in the 2000 CO plan. The 2000 CO plan estimates that the CAT MATCH program would reduce CO emissions by 0.3 tpd in 2000, 1.8 tpd in 2010, and 2.3 tpd in 2020, and refers to our Voluntary Mobile Source Emission Reduction Program (VMEP) policy, described below, in support of the identification of the CO emissions reductions from that voluntary program as part of the overall CO control strategy.

A memorandum from Richard Wilson dated October 24, 1997 sets forth our policy and interpretation regarding the granting of explicit credit for VMEPs under section 110 of the Act. The VMEP policy was developed since we wanted to encourage areas to consider innovative methods in achieving air quality goals. Under the VMEP policy, emissions credit can be approved under certain circumstances and if the appropriate agency has committed to monitoring and evaluating the effectiveness of the voluntary measure, to reporting on the results of the evaluation, and to remedying any emissions shortfall if the voluntary measure proves to be less effective than projected in the plan.

We have evaluated the CAT MATCH program under our VMEP policy and conclude that the emissions reduction credit in the 2000 CO plan for that voluntary program is appropriate. We also have determined that the CAT MATCH program complies with section 187(b)(2) of the Act. Therefore, we propose to approve the CAT MATCH program under section 187(b)(2) of the Act, and we propose to approve into the Nevada SIP the commitments by RTC to develop, implement, monitor, report, and remedy any emissions shortfalls from this voluntary program under RTC's Resolution No. 177 (adopted June 10, 1999) and Resolution No. 186 (adopted June 8, 2000). Our full review of the TCM/TDM measure is included in the TSD for this proposed action.

Alternative Fuels Program

The Energy Policy Act of 1992 (EPACT) requires federal, state, and fuel provider fleets to acquire alternative fuel vehicles. The State of Nevada has chosen to develop a program that extends alternative fuel requirements to local government agencies in their two most populated counties, Washoe and Clark, and that provides for a more aggressive schedule for implementation than would otherwise be required under EPACT. The State law establishing this program is set forth at NRS chapter 486A. NRS chapter 486A authorizes the State Environmental Commission (SEC) to promulgate implementing regulations, and SEC's regulations are set forth in NAC chapter 486A. Specifically, SEC's regulations require applicable government agencies to acquire and use an increasing proportion of alternative fuel vehicles up to 90% for year 2001 and beyond when acquiring additional or replacement vehicles for its fleet. The program began in 1995, and the 2000 CO plan indicates that nearly all applicable agencies have chosen to comply by acquiring natural gas vehicles and that presently there are over 1,400 alternative fuel vehicles operating in Las Vegas Valley. The regulations also include record keeping and reporting requirements. Under the regulatory scheme, the State Department of Conservation and Natural Resources is responsible for enforcement.

The 2000 CO plan included the alternative fuels program set forth in NAC chapter 486A, as revised through April 2000, as an additional control measure. In estimating emission reductions in Clark County associated with this measure, the 2000 CO plan assumes that most fleets have chosen to purchase CNG vehicles to comply with the alternative fuel regulations and that the number of CNG vehicles is expected to be 2,925 by year 2010, and 3,568 by year 2020. Under these assumptions, implementation of the alternative fuel vehicle programs results in emission reductions of 0.4 tpd in 2000, 1.1 tpd in 2010 and 1.4 tpd in 2020. The State's alternative fuel program contributes to the effort to attain and maintain the CO NAAQS within Las Vegas Valley and meets all CAA requirements (see the TSD for more details). Therefore, we are proposing to approve the alternative fuel program into the Nevada SIP for the Las Vegas Valley CO nonattainment area. Specifically, we propose to approve, into the Nevada SIP, the legal authority vested in SEC under NRS Chapter 486A and the implementing regulations set forth in NAC Chapter 486A, as amended through April 20, 2000 by the State Environmental Commission.

H. Are There Controls on Stationary Sources of CO?

Section 172(c)(5) of the Act requires states with nonattainment areas to revise their SIPs to include a permit program for the construction and operation of new or modified major stationary sources in the nonattainment areas.

Within Clark County, the State of Nevada, rather than the county, has jurisdiction over plants which generate electricity by using steam produced by the burning of fossil fuel. See NRS 445B.500. With respect to such plants, EPA is not requiring the State to submit new source review permit regulations under section 172(c)(5) of the Act because the State has adopted a regulation that prohibits new power plants or major modifications to existing power plants under its jurisdiction within the Las Vegas Valley nonattainment area (*i.e.*, hydrographic area 212). See NAC 445B.22083.

Clark County has jurisdiction over all other stationary sources within the county, and with respect to those sources, we approved the new source review permit program for Clark County in 1999. See 64 FR 25210 (May 11, 1999). This program defines major stationary sources of CO within Las Vegas Valley as those that have the potential to emit 70 tons per year or more, which is more stringent than required under section 302(j) of the Act

and requires such new or modified sources locating within the nonattainment area to obtain offsets in addition to installing control equipment representing the lowest achievable emission rate.

However, on August 29, 2001, the U.S. Court of Appeals for the Ninth Circuit vacated our approval of Clark County's new source review program. See *Hall* v. *EPA*, 273 F.3d 1146 (9th Cir. 2001). The court vacated our approval, not because EPA had acted unreasonably in finding that the program complies with the specific requirements of section 172(c)(5), but rather, because EPA did not have an adequate basis under section 110(l) of the Act to conclude that the new program, even if it met the minimum requirements of section 172(c)(5), would not interfere with attainment of the NAAQS by the applicable deadline.

We intend to re-propose an action on the new source review program in a separate notice in the near future. However, we note here that the emissions inventory and attainment demonstration from the 2000 CO plan that we are proposing to approve in this notice includes stationary sources and the projections of emissions from those sources appear to be generally consistent with the new source review program as submitted to EPA. Specifically, the 2000 CO plan assumes that CO emissions from major CO stationary sources will remain unchanged (which is consistent with the offset requirement in their new source review program) whereas the plan projects growth in CO emissions from non-major stationary sources (which are not subject to federally-enforceable offsets under their program).

Section 187(c) of the Act requires that, in the case of CO nonattainment areas classified as serious and subject to significant stationary source emissions of CO, the term ''major stationary source'' is to include any stationary source which emits, or has the potential to emit, 50 tons per year or more of CO. The 2000 CO plan concludes that Las Vegas Valley is not subject to significant stationary source emissions of CO and thus not subject to the requirements of section 187(c). Generally, significance in this context is associated with areas with individual stationary sources that generate 5,000 tons of CO per year or more. (See guidance provided in a memorandum from William G. Laxton, Director, Technical Support Division, EPA, dated May 13, 1991.) Since the highest CO-emitting facility shown in the stationary source inventory for the 2000 CO plan emits only 1,100 tons per year of CO, we agree with the conclusion that stationary sources are not significant contributors to ambient CO levels in Las Vegas Valley and that section 187(c) of the Act does not apply within the Las Vegas Valley CO nonattainment area.

I. What Expected Growth of Vehicle Traffic Is Projected for the Area?

Section 187(a)(2)(A) of the Act requires states with CO nonattainment areas with design values greater than 12.7 ppm, such as Las Vegas Valley, to submit a plan revision that contains a forecast of vehicle miles traveled (VMT) in the nonattainment area for each year until attainment of the CO NAAQS. Also, this plan revision must provide for annual updates of the VMT forecasts to be submitted to EPA along with annual reports regarding the extent to which the preceding annual forecasts proved to be accurate. These annual reports must contain estimates of actual VMT in each year for which a VMT forecast was required.

The 2000 CO plan provides VMT forecasts for every year from 1997 through the attainment year of 2000 and then nearly every year between 2001 and 2030. The VMT forecasts were estimated using recent transportation modeling results from RTC that incorporated more recent socioeconomic data than had been used for VMT forecasts contained in the earlier plans. The VMT forecasts are displayed in Table 7–1 of Chapter 7 of the 2000 CO plan. The forecasts are broken down by roadway type. The forecasts predict increases in VMT of roughly 5% each year through 2005 consistent with recent trends, then roughly 4% each thereafter until 2020, and then marginal decreases each year between 2020 and 2030 based on an assumption of highway saturation by that time resulting in a mode shift to mass transit, ride sharing, and other modes.

RTC is the local agency responsible for preparing VMT forecasts. Through Resolution No. 149, as adopted on July 13, 1995, RTC has committed to preparing annual VMT estimates and forecasts and to submitting these reports (''VMT tracking reports'') to EPA. Under section 187(a)(3) of the Act, annual VMT tracking reports provide a potential basis for triggering implementation of contingency measures in the event that estimates of actual VMT exceed the forecasts contained in the prior annual VMT tracking report.

We propose to approve the VMT forecasts contained in the 2000 CO plan as meeting the section 187(a)(2)(A) requirements. However, it is noted that section 187(a)(2)(A) does not require forecasts extending as far into the future as those provided in the 2000 CO plan, and, while our approval of the emissions budgets through 2020 discussed in this notice implies approval of the VMT forecasts through 2020, no such implied approval is intended for VMT forecasts beyond 2020. Also, we propose to approve RTC's commitment through Resolution No. 149 to prepare and submit annual VMT tracking reports.

J. Does the Plan Include Contingency Measures?

Section 187(a)(3) of the Act requires states with CO nonattainment areas with design values greater than 12.7 ppm, such as Las Vegas Valley, to submit a plan revision that provides for contingency measures. The Act specifies that such measures are to be implemented if any estimate of VMT submitted in an annual VMT tracking report exceeds the VMT predicted in the most recent prior forecast or if the area fails to attain the NAAQS by the attainment date. As a general rule, contingency measures must be structured to take effect without further action by the state or EPA upon the occurrence of certain triggering events.

EPA believes that, for exceedances of a VMT forecast, one appropriate choice of contingency measures would be to provide for the implementation of sufficient VMT reductions or emissions reductions to counteract the effect of 1 year's growth in VMT while the state revised its SIP (including VMT projections) to provide for attainment by the applicable date. These measures may offset either the excess VMT in the nonattainment area or the additional CO emissions in the area that are attributable to the additional VMT. In the case of Las Vegas Valley, the annualized rate of growth in VMT over the 2000 to 2005 period is approximately 5 percent; therefore, the contingency measures should have the potential to achieve that level of reduction in VMT or a corresponding reduction in CO emissions, which would be approximately 16 tons per day based on the 2000 CO motor vehicle estimate of 310 tons per day.

For a failure to attain the CO NAAQS by the attainment date, EPA believes that contingency measures should have the potential to provide a reduction in CO emissions equivalent to 3 percent of the CO inventory. In this instance, 3 percent of the total CO inventory projection in 2000 (387 tons per day) is approximately 12 tons per day.

The three contingency measures included in the 2000 CO plan include:

—On Board Diagnostics II (OBD II) Testing; [9]
—Lower I/M Program Cutpoints; and
—On Road Remote Sensing.

From 1997 through 2000, when the Las Vegas serious area plan was being developed, the implementation deadline for mandatory OBD testing in I/M programs had not yet passed, and the plan identified OBD II testing as a contingency measure that would be triggered by the occurrence of either unanticipated growth in VMT or a CO exceedance. However, the deadline for mandatory OBD testing is now expired. See 66 FR 18156 (April 5, 2001). Normally, a required measure does not qualify as contingency measure; however, a measure that represents a requirement but that is designed to allow for implementation prior to its implementation deadline may qualify as a short-term contingency measure. In this instance, because the implementation deadline for mandatory OBD testing had not passed at the time of plan development and adoption and the emissions benefits from mandatory OBD testing were not included in the attainment demonstration, and because of Clark County's commitment to provide documentation and additional measures if necessary, as explained below, we propose to approve OBD testing as a contingency measure of the 2000 CO plan for the purposes of section 187(a)(3) of the Act. As noted previously, in today's action, we are proposing to approve (under our parallel processing procedure) revisions to the I/M program to implement OBD II testing based on draft revisions to the implementing regulations (specifically, revision to NAC 445B.580) submitted by NDEP under a letter dated January 30, 2002. Thus, as a practical matter, this contingency measure will not actually be contingent upon occurrence of any particular event but will be implemented fully by the end of 2002.

The 2000 CO plan did not provide emission reduction estimates for implementation of OBD II testing because of the limitations of the vehicle emissions model (MOBILE5b) available at the time of plan preparation. However, in adopting the 2000 CO plan (resolution dated August 1, 2000), Clark County committed to preparing and submitting a plan revision to EPA that quantifies the actual benefits of the contingency measures contained in the plan, within one year of the release date of pending applicable guidance protocols and models. The County also committed to monitoring the emission reductions associated with the plan's control measures and remedying in a timely fashion any shortfall for the purpose of complying with SIP control measure requirements of the Act.

In January 2002, EPA approved and announced the availability of the MOBILE6 motor vehicle emission factor model for official use outside of California. See 67 FR 4254 (January 29, 2002). Unlike MOBILE5b, MOBILE6 has the capability of quantifying the emissions reductions associated with implementation of OBD. Based on Clark County's commitment cited above, we anticipate that the County will develop and, via NDEP, submit emissions estimates by the end of January 2003 showing the emissions reductions associated with OBD testing in Clark County and identifying additional contingency measures, if necessary, to provide needed emissions reductions if VMT growth exceeds projections or if the CO NAAQS is exceeded.

In addition, the Nevada State Environmental Commission adopted a resolution dated April 9, 1999 that directs NDEP, DMV, the Department of Agriculture, and Clark County to work together to identify and propose to the appropriate adopting body the most cost-effective and reasonably available control strategies necessary to achieve and maintain the NAAQS and to ensure conformity between the transportation improvement program and the SIP. Through this resolution, the Nevada State Environmental Commission further committed itself to adopting appropriate emission reduction measures as necessary to ensure that the NAAQS can be achieved and maintained in Las Vegas Valley.

We agree that MOBILE6 is the appropriate tool to use in estimating emissions reductions from OBD testing, and we agree that implementing OBD testing will provide substantial emissions reductions beyond those already accounted for in the 2000 CO plan. We expect that OBD testing will ultimately be shown by Clark County to provide emissions reductions beyond the minimum we believe contingency measures must provide. Taken together with the County's commitments to provide emissions documentation and remedial contingency measures, if necessary, and the Nevada State Environmental Commission's April 9, 1999 resolution, we propose to approve OBD II testing as meeting section 187(a)(3) requirements.

We are proposing to disapprove the other contingency measures in the 2000 CO plan, lower I/M program cutpoints and on-road remote sensing. With respect to lower I/M program cutpoints, we are proposing disapproval because the measure has not been developed to allow for implementation (upon the occurrence of triggering events) without further action by the State. With respect to on-road remote sensing, in proposing disapproval, we note that a minimum level of on-road testing is required for all enhanced I/M programs (see 40 CFR 51.51.351(b), and to the extent that this particular measure provides for that minimum level of testing, it does not qualify as a contingency measure.

An on-road testing program designed to obtain measurable emission reductions over and above those already predicted to be achieved by other aspects of the I/M program can serve as a contingency measure, but the description and documentation of the on-road remote sensing contingency measure as included in the 2000 CO plan does not provide us with the basis to conclude that it would provide emissions reductions beyond those already predicted to be achieved by other aspects of the I/M program. Nonetheless, we have concluded that these two measures are not necessary for plan approval, and we propose to find that OBD II testing and related commitments are sufficient in themselves to comply with section 187(a)(3) of the Act. Therefore, our disapproval of these contingency measures, if finalized, would not trigger sanctions clocks under section 179(a) of the Act.

K. Are the Emissions Budgets Approvable?

Section 176(c)(1) of the Act prohibits federal agencies from permitting, approving, or funding any activity in nonattainment or maintenance areas that does not conform to a SIP once the SIP has been approved by EPA under section 110 of the Act. Section 176(c)(1) also prohibits metropolitan planning organizations (MPOs), such as the Clark County RTC, from approving any project, program, or plan that does not conform to a SIP once the SIP has been approved by EPA under section 110 of the Act. With regards to regional transportation plans and program, MPOs must demonstrate consistency between motor vehicle emissions estimates under those plans and

[9] Some variety of OBD system has been an option on certain vehicle models since the early 1980's, standardized OBD systems (also known as OBD II) were not introduced until MY 1994, and such systems did not appear on all new light-duty vehicles sold in this country until MY 1996. Therefore, for I/M purposes, EPA does not require or recommend that pre-1996 MY vehicles be subject to OBD inspections. Additionally, EPA's MOBILE6 emission factor model will not provide emission reduction on pre-1996 MY vehicles. (Nevada DMV intends to submit final adopted regulations that are consistent with EPA's definition for OBD systems.)

programs and corresponding motor vehicle emissions budgets contained in the applicable SIP. On March 2, 1999, the United States Court of Appeals for the District of Columbia Circuit issued a decision on *Environmental Defense Fund* v. *EPA,* 167 F.3d 641 (DC Cir. 1999), that we must make an affirmative determination that motor vehicle emission budgets in submitted SIPs are adequate before transportation agencies can use those budgets in conformity determinations under the transportation conformity rule set forth in 40 CFR 93, subpart A.

Upon receipt of the 2000 CO plan, we announced receipt of the plan on the Internet and requested public comment by September 29, 2000. The November 20, 2000 letter from Amy Zimpfer to Allen Biaggi and the November 30, 2000 **Federal Register** Notice (65 FR 71313) announced our decision that the motor vehicle budgets in the CO Plan are adequate. The technical support document that was attached to the letter summarizes how the motor vehicle CO emission budgets for the years 2000, 2010 and 2020 meet the adequacy criteria contained in the conformity rule (40 CFR 93.118(e)(4)). These budgets are shown in Table 7.

TABLE 7.—LAS VEGAS VALLEY PEAK SEASON EMISSION BUDGETS

[Emissions (tons/day)]

Source category	2000	2010	2020
On-road Motor Vehicles	310.2	329.5	457.4

Source: 2000 CO Plan, Table 8–3.

The 2000 CO plan predicts that the overall downward CO emissions trend in the nonattainment area will reverse after year 2000 and will, before 2020, exceed valley-wide CO emissions estimated for 1996 (*i.e.*, 473.56 tons per day) when CO NAAQS violations were recorded; however, the results of area-wide and hot-spot modeling provided in the 2000 CO plan indicate that CO NAAQS violations would not be expected in the future despite these increases in overall CO emissions. The explanation lies in the wider geographic distribution of traffic and related CO emissions in 2020 compared to conditions that prevailed in the mid-1990's due to land use development patterns that disperse new development and related traffic congestion into outlying areas. Thus, the CO motor vehicle emission budgets in the 2000 CO plan can be approved despite the increases relative to emissions levels associated with past NAAQS violations.

We re-affirm the evaluation provided in the TSD supporting the adequacy determination and propose to approve the CO motor vehicle emission budgets (shown in Table 7, above) contained in the 2000 CO plan as meeting the purposes of section 176(c)(1) and the transportation conformity rule at 40 CFR part 93, subpart A.

L. Summary of EPA's Proposed Actions

Under section 110(k)(3) of the Act, we propose the following actions on elements of the 1995 CO plan, the vehicle I/M program for Las Vegas Valley, and the 2000 CO plan.

(1) Approval of procedural requirements, under section 110(a)(1) of the Act;

(2) Approval of baseline and projected emission inventories, under sections 172(c)(3) and 187(a)(1) of the Act and approval of reasonable further progress, under sections 172(c)(2) and 187(a)(7) of the Act;

(3) Approval of attainment demonstration, under section 187(a)(7) of the Act;

(4) Approval of revisions to the Nevada vehicle I/M program for Las Vegas Valley and Boulder City under section 187(a)(6) of the Act. Specifically, we propose to approve the statutory and regulatory basis for the revised program in NRS, title 40, section 445B.210 and sections 445B.700 through 445B.845, and title 43, sections 481.047–481.083, 482.155–482.283, 482.385, 482.461, 482.565, and 484.644–484.6441, as amended by Nevada through 2001, and NAC sections 445B.400 through 445B.735 (not including 445B.576, 445B.577, 445B.578), as amended through March 8, 2002 by SEC and DMV, and, in the case of draft revisions to NAC 445B.580, as submitted by NDEP by letter dated January 30, 2002. We will consider final action on the vehicle I/M program once we receive the final adopted version of NAC 445B.580 (and other NAC sections that specify final test procedures and equipment used for OBD checks);

(5) Approval of the State's low RVP wintertime requirement for gasoline sold in Clark County. Specifically, we propose to approve NAC 590.065 as adopted on October 28, 1998 by the State Board of Agriculture;

(6) Approval of the County's wintertime Cleaner Burning Gasoline (CBG) regulation under section 211(c)(4)(C) of the Act. Specifically, we propose to approve CCDAQM section 54 as adopted on July 24, 2001 by CCAQMB based on the condition that the State submit to EPA the CCAQMB version of the rule prior to our taking final action. CCAQMB's adopted version of the CBG rule (CCDAQM section 54) is the same as the Board of Health's CBG regulation that had been submitted to EPA in August 2000 as one of the principal control measures in the 2000 CO plan developed to meet the applicable requirements under part D of title I of the Act for the Las Vegas CO nonattainment area but for changes in the references to the applicable agency;

(7) Approval of RTC's CAT MATCH commuter incentive program under section 187(b)(2) of the Act and our voluntary mobile source emissions reduction program policy. Specifically, we propose to approve CAT MATCH guidelines as set forth in RTC's Resolution No. 177, adopted on June 10, 1999, and the commitments to implement and monitor the program, and prepare annual reports, as set forth in RTC's Resolution No. 186, adopted on June 8, 2000;

(8) Approval of the Alternative Fuels Program for government vehicles in Clark County. Specifically, we propose to approve the regulations set forth in NAC Chapter 486A, as amended through April 20, 2000 by the State Environmental Commission;

(9) Approval of a determination that stationary sources do not contribute significantly to ambient CO levels in the Las Vegas CO nonattainment area for the purposes of section 187(c) of the Act;

(10) Approval of VMT forecasts and the responsible agencies' commitments to revise and replace the VMT projections as needed and monitor actual VMT levels in the future, under section 187(a)(2)(A) of the Act. Specifically, we propose to approve RTC's commitments to prepare VMT estimates, forecasts, and annual VMT tracking reports as set forth in Resolution No. 149, as adopted on July 13, 1995;

(11) Approval of contingency measures under section 187(a)(3) of the Act. Specifically, we propose to approve the revisions to NAC 445B.580 related to implementation of OBD testing based on the draft revisions to that section submitted by NDEP under letter dated January 30, 2002 and the commitments contained in Resolution of the Clark County Board of Commissioners to Adopt the Las Vegas Valley Carbon Monoxide State Implementation Plan, adopted August 1, 2000, to monitor the emission reductions associated with the plan's control measures, to remedy in a timely fashion any shortfall, to prepare and submit a plan revision to EPA that quantifies the actual benefits of the contingency measures contained in the plan, within one year of the release date of pending applicable guidance protocols and models, and to the resolution adopted by the Nevada State Environmental Commission on April 9, 1999;

(12) Disapproval of the other two contingency measures contained in the 2000 CO plan, lower I/M program cutpoints and on-road remote sensing, but our disapproval, if finalized, would not trigger sanctions clocks because we are proposing to find that OBD II testing and related commitments themselves provide the necessary compliance with section 187(a)(3) of the Act; and

(13) Approval of the CO motor vehicle emissions budgets for 2000, 2010, and 2020 as meeting the purposes of section 176(c)(1) and the transportation conformity rule at 40 CFR part 93, subpart A. All future transportation conformity determinations for CO in Clark County must be based on the CO Complex model with MOBILE5b until the grace period for MOBILE6 has concluded.

III. Request for Public Comment

We are soliciting public comment on all aspects of this proposal. These comments will be considered before taking final action. To comment on today's proposal, you should submit comments by mail or in person (in triplicate if possible) to the **ADDRESSES** section listed in the front of this document. Your comments must be received by February 27, 2003 to be considered in the final action taken by EPA.

IV. Administrative Requirements

A. Executive Order 12866

The Office of Management and Budget (OMB) has exempted this regulatory action from Executive Order 12866, entitled ''Regulatory Planning and Review.''

B. Executive Order 13045

Executive Order 13045, entitled Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This proposed rule is not subject to Executive Order 13045 because it does not involve decisions intended to mitigate environmental health or safety risks.

C. Executive Order 13132

Executive Order 13132, entitled Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612, Federalism, and 12875, Enhancing the Intergovernmental Partnership. Executive Order 13132 requires EPA to develop an accountable process to ensure ''meaningful and timely input by state and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that 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.'' Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or EPA consults with state and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts state law unless the Agency consults with state and local officials early in the process of developing the proposed regulation.

This rule 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, as specified in Executive Order 13132, because it merely proposes to approve a state plan implementing a federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act. Thus, the requirements of section 6 of the Executive Order do not apply to this rule.

D. Executive Order 13175

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 6, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This proposed rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. This action does not involve or impose any requirements that affect Indian Tribes. Thus, Executive Order 13175 does not apply to this rule.

E. Executive Order 13211

This proposed rule is not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

F. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies 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 small governmental jurisdictions. This proposed rule will not have a significant impact on a substantial number of small entities because SIP approvals under section 110 and subchapter I, part D of the Clean Air Act do not create any new requirements but simply approve requirements that the state is already imposing. Therefore, because the Federal SIP approval does not create any new requirements, I certify that this action will not have a significant economic impact on a substantial

number of small entities. Moreover, due to the nature of the Federal-State relationship under the Clean Air Act, preparation of flexibility analysis would constitute Federal inquiry into the economic reasonableness of state action. The Clean Air Act forbids EPA to base its actions concerning SIPs on such grounds. *Union Electric Co.,* v. *U.S. EPA,* 427 U.S. 246, 255–66 (1976); 42 U.S.C. 7410(a)(2).

G. Unfunded Mandates

Under section 202 of the Unfunded Mandates Reform Act of 1995 (''Unfunded Mandates Act''), signed into law on March 22, 1995, EPA must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in estimated annual costs to state, local, or tribal governments in the aggregate; or to the private sector, of $100 million or more. Under section 205, 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 EPA to establish a plan for informing and advising any small governments that may be significantly or uniquely impacted by the rule. EPA has determined that the proposed approval action does not include a Federal mandate that may result in estimated annual costs of $100 million or more to either state, local, or tribal governments in the aggregate, or to the private sector. This Federal action proposes to approve pre-existing requirements under state or local law, and imposes no new requirements. Accordingly, no additional costs to state, local, or tribal governments, or to the private sector, result from this action.

H. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use ''voluntary consensus standards'' (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Intergovernmental regulations, Reporting and recordkeeping requirements.

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

Dated: January 15, 2003.

Keith Takata,

Acting Regional Administrator, Region 9.

[FR Doc. 03–1774 Filed 1–27–03; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[AL–058–1–200312b; FRL–7444–8]

Approval and Promulgation of State Plan for Designated Facilities and Pollutants: Alabama

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA proposes to approve the section 111(d)/129 State Plan submitted by the Alabama Department of Environmental Management (ADEM) for the State of Alabama on February 21, 2002, for implementing and enforcing the Emissions Guidelines applicable to existing Commercial and Industrial Solid Waste Incinerators. The Plan was submitted by ADEM to satisfy Federal Clean Air Act requirements. In the Final Rules Section of this **Federal Register**, the EPA is approving the Alabama State Plan revision as a direct final rule without prior proposal because the Agency views this revision as a noncontroversial submittal and anticipates no adverse comments. A detailed rationale for the approval is set forth in the direct final rule. If no significant, material, and adverse comments are received in response to this rule, no further activity is contemplated. If EPA receives adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule based on this rule. The EPA will not institute a second comment period on this document. Any parties interested in commenting on this document should do so at this time.

DATES: Written comments must be received on or before February 27, 2003.

ADDRESSES: Written comments should be addressed to: Joydeb Majumder, EPA Region 444, Air Toxics and Management Branch, 61 Forsyth Street, SW, Atlanta, Georgia 30303–8960. Copies of documents relative to this action are available for inspection during normal business hours at the above listed Region 4 location. Anyone interested in examining this document should make an appointment with the office at least 24 hours in advance.

FOR FURTHER INFORMATION CONTACT: Joydeb Majumder at (404) 562–9121 or Sean Lakeman at (404) 562–9043.

SUPPLEMENTARY INFORMATION: For additional information see the direct final rule which is published in the rules section of this **Federal Register**.

Dated: January 16, 2003.

A. Stanley Meiburg,

Acting Regional Administrator, Region 4.

[FR Doc. 03–1868 Filed 1–27–03; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[DA 03–185, MB Docket No. 03–20, RM–10634]

Television Broadcast Service; Christiansted, VI

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: The Commission requests comments on a petition filed by Virgin Blue, Inc., requesting the substitution of channel 39 for station WCVI–TV's channel 27. TV Channel 39 can be allotted to Christiansted, Virgin Islands with a zero offset consistent with the minimum distance separation requirements of sections 73.610 and 73.698 of the Commission's Rules. The coordinates for channel 39 at Christiansted are 17–44–53 N. and 64–43–40 W.

DATES: Comments must be filed on or before March 24, 2003, and reply comments on or before April 8, 2003.

ADDRESSES: Federal Communications Commission, 445 12th Street, SW., Room TW–A325, Washington, DC 20554. In addition to filing comments with the FCC, interested parties should serve the petitioner, or its counsel or consultant, as follows: Victor A. Gold, President, WCVI–TV, PO Box 24027, Christiansted, Virgin Islands 00824 (petitioner).

FOR FURTHER INFORMATION CONTACT: Pam Blumenthal, Media Bureau, (202) 418–1600.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's notice of proposed rulemaking, MB Docket No.

03–20, adopted January 22, 2003, and released January 29, 2003. The full text of this document is available for public inspection and copying during regular business hours in the FCC Reference Information Center, Portals II, 445 12th Street, SW., Room CY–A257, Washington, DC, 20554. This document may also be purchased from the Commission's duplicating contractor, Qualex International, Portals II, 445 12th Street, SW., Room CY–B402, Washington, DC, 20554, telephone 202–863–2893, facsimile 202–863–2898, or via-e-mail *qualexint@aol.com.*

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 rulemaking 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

Television broadcasting.

For the reasons discussed in the preamble, the Federal Communications Commission proposes to amend 47 CFR part 73 as follows:

PART 73—RADIO BROADCAST SERVICES

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

Authority: 47 U.S.C. 154, 303, 334 and 336.

§ 73.606 [Amended]

2. Section 73.606(b), the Table of Television Allotments under Virgin Islands, is amended by removing channel 27 and adding channel 39 at Christiansted.

Federal Communications Commission.

Barbara A. Kreisman,

Chief, Video Division, Media Bureau.

[FR Doc. 03–1837 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

RIN 1018–AI25

Endangered and Threatened Wildlife and Plants; Determinations of Prudency for Two Mammal and Four Bird Species in Guam and the Commonwealth of the Northern Mariana Islands and Designations of Critical Habitat for One Mammal and Two Bird Species

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Proposed rule; reopening of comment period.

SUMMARY: We, the U.S. Fish and Wildlife Service, announce the reopening of the public comment period for the proposed rule to designate critical habitat for the Mariana fruit bat and the Guam Micronesian kingfisher on Guam, and the Mariana crow on Guam and Rota and associated draft economic analysis. The proposed designations of critical habitat were published in the **Federal Register** on October 15, 2002. The extension of the comment period and notice of availability of the draft economic analysis were published in the **Federal Register** on December 5, 2002. On December 8, 2002, Guam and Rota sustained extensive damage from Super Typhoon Pongsona and were federally declared disaster areas. The extended comment period ended on January 6, 2003; therefore, we are reopening the comment period to allow additional time for all interested parties to consider the information and submit written comments on the proposal and associated draft economic analysis. Comments previously submitted need not be resubmitted as they will be incorporated into the public record and will be fully considered in preparation of the final rule.

DATES: We will accept public comments until February 18, 2003.

ADDRESSES: Written comments and information should be submitted to Field Supervisor, U.S. Fish and Wildlife Service, Pacific Islands Office, 300 Ala Moana Blvd., PO Box 50088, Honolulu, HI 96850–0001. Copies of the draft economic analysis are available on the Internet at *http://pacificislands.fws.gov* or by request from the Field Supervisor at the above address and telephone 808/541–3441. Copies of the draft economic analysis also are available on Guam at the Belt Collins Guam Office, GCIC Building, 414 West Soledad Avenue, Hagatna, Guam, phone 671/477–6148, and on Rota at the Northern Marianas College, Tatachog Campus, Rota, telephone 670/532–9477. For further instructions on commenting, refer to Public Comments Solicited section of this notice.

FOR FURTHER INFORMATION CONTACT: Paul Henson, Field Supervisor, Pacific Islands Office, at the above address (telephone: 808/541–3441; facsimile: 808/541–3470).

SUPPLEMENTARY INFORMATION:

Background

On October 15, 2002 (67 FR 63738), we proposed designating approximately 10,053 hectares (ha) (24,840 acres (ac)) in two units on the island of Guam for the Mariana fruit bat (*Pteropus mariannus mariannus*) and the Guam Micronesian kingfisher (*Halcyon cinnamomina cinnamomina*) (67 FR 63738). For the Mariana crow (*Corvus kubaryi*), we proposed designating approximately 9,325 ha (23,042 ac) in two units on the island of Guam and approximately 2,462 ha (6,084 ac) in one unit on the island of Rota in the CNMI. On Guam, the boundaries of the proposed critical habitat units for the Mariana fruit bat and Guam Micronesian kingfisher are identical and the boundaries of the proposed critical habitat for the Mariana crow are contained within these identical boundaries. On Rota, critical habitat is proposed only for the Mariana crow.

Critical habitat receives protection from destruction or adverse modification through required consultation under section 7 of the Act (16 U.S.C. 1531 *et seq.*) with regard to actions carried out, funded, or authorized by a Federal agency. Section 4(b)(2) of the Act requires that the Secretary shall designate or revise critical habitat based upon the best scientific and commercial data available, and after taking into consideration the economic impact of specifying any particular area as critical habitat. A draft economic analysis of the proposed critical habitat designation was prepared and a notice of availability was published in the **Federal Register** on December 5, 2002 (67 FR 72407); with a request for public comment on both the proposed rule and economic analysis by January 6, 2003. The draft economic analysis shows that over a 10-year period, the estimated total direct cost on Guam would be approximately $1.4 million and the estimated total direct cost on Rota would be approximately $149,000. The draft economic analysis is available on the

Internet and from the mailing address in the Public Comments Solicited section below.

Public Comments Solicited

We are now announcing the reopening of the comment period for the proposed designation of critical habitat for the Mariana fruit bat and the Guam Micronesian kingfisher on Guam, and the Mariana crow on Guam and Rota and associated draft economic analysis. On December 8, 2002, Guam and Rota sustained extensive damage from Super Typhoon Pongsona and were declared Federal disaster areas. We are reopening the comment period until the date specified in **DATES**. The reopening of the comment period gives additional time for all interested parties to consider the information and submit written comments on the proposal and the associated draft economic analysis.

We will accept written comments and information during this reopened comment period. If you wish to comment, you may submit your comments and materials concerning this proposal by any of several methods:

(1) You may submit written comments and information to the Field Supervisor, U.S. Fish and Wildlife Service, Pacific Islands Fish and Wildlife Office, 300 Ala Moana Blvd., PO Box 50088, Honolulu, HI 96850–0001.

(2) You may send comments by electronic mail (e-mail) to: *Guam_crithab@r1.fws.gov*. If you submit comments by e-mail, please submit them as an ASCII file and avoid the use of special characters and any form of encryption. Please also include ''Attn: RIN 1018–AI25'' and your name and return address in your e-mail message.

(3) You may hand-deliver comments to our Honolulu Fish and Wildlife Office at the address given above.

Comments and materials received, as well as supporting documentation used in preparation of the proposal to designate critical habitat, will be available for inspection, by appointment, during normal business hours at the address under (1) above. Copies of the draft economic analysis are available on the Internet at *http://pacificislands.fws.gov* or by request from the Field Supervisor at the address under **ADDRESSES** and phone number under **FOR FURTHER INFORMATION CONTACT** above.

Author(s)

The primary author of this notice is Fred Amidon (see **ADDRESSES**).

Authority

The authority for this action is the Endangered Species Act of 1973 (16 U.S.C. 1531 *et seq.*).

Dated: January 15, 2003.

Paul Hoffman,

Acting Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 03–1799 Filed 1–27–03; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

RIN 1018–AI46

Endangered and Threatened Wildlife and Plants; Proposed Designation of Critical Habitat for the Preble's Meadow Jumping Mouse

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Proposed rule; extension of public comment period and notice of availability of draft economic analysis and draft environmental assessment.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce the availability of the draft economic analysis and draft environmental assessment for the proposal to designate critical habitat for the Preble's meadow jumping mouse (*Zapus hudsonius preblei*) under the Endangered Species Act of 1973, as amended. We also are providing notice of the final planned extension of the public comment period for the proposal to designate critical habitat for this species to allow all interested parties to comment on and request changes to the proposed critical habitat designation, as well as the associated draft economic analysis and environmental assessment. Over a 10-year time period, the total section 7-related direct costs associated with the Preble's meadow jumping mouse listing and critical habitat are estimated at $74 million to $172 million. Comments previously submitted need not be resubmitted as they have been incorporated into the public record as part of this extended comment period and will be fully considered in preparation of the final rule.

DATES: We will consider all comments that we receive on or before February 27, 2003. Any comments that we receive after the closing date may not be considered in the final decision on this proposal.

ADDRESSES: You may submit written comments and information to Preble's Meadow Jumping Mouse Comments, Colorado Ecological Services Field Office, U.S. Fish and Wildlife Service, 755 Parfet Street, Suite 361, Lakewood, CO 80215, or by facsimile to 303–275–2371. You may hand deliver written comments to our Colorado Ecological Services Field Office at the address given above. You may send comments by electronic mail (e-mail) to *fw6_pmjm@fws.gov*. See the ''Public Comments Solicited'' section below for file format and other information on electronic filing.

You may obtain copies of the draft economic analysis and draft environmental assessment, review comments and materials received, and review supporting documentation used in preparation of this proposed rule, by appointment, during normal business hours, at the U.S. Fish and Wildlife Service's Colorado Field Office. The documents also are available on the Internet at *http://mountain-prairie.fws.gov/preble.*

FOR FURTHER INFORMATION CONTACT: LeRoy Carlson, Colorado Field Supervisor, at the above address or telephone 303–275–2370.

SUPPLEMENTARY INFORMATION:

Background

The Preble's meadow jumping mouse (Preble's), a small rodent in the family Zapodidae, is known to occur only in eastern Colorado and southeastern Wyoming. It lives primarily in heavily vegetated riparian habitats and immediately adjacent upland habitats. Habitat loss and degradation caused by agricultural, residential, commercial, and industrial development resulted in the Preble's being listed as a threatened species throughout its range on May 13, 1998 (62 FR 26517).

On July 17, 2002 (67 FR 47153), we proposed to designate critical habitat for the Preble's meadow jumping mouse pursuant to the Endangered Species Act (Act) of 1973, as amended (16 U.S.C. 1531 *et seq.*). The proposed designation includes 19 habitat units totaling approximately 23,248 hectares (57,446 acres) found along 1,058.1 kilometers (657.5 miles) of rivers and streams in the States of Colorado and Wyoming.

Critical habitat identifies specific areas, both occupied and unoccupied, that are essential to the conservation of a listed species and that may require special management considerations or protection. If the proposed rule is made final, section 7 of the Act will prohibit destruction or adverse modification of critical habitat by any activity funded, authorized, or carried out by any Federal agency, and Federal agencies

proposing actions affecting areas designated as critical habitat must consult with us on the effects of their proposed actions, pursuant to section 7(a)(2) of the Act.

Section 4 of the Act requires that we consider economic and other relevant impacts prior to making a final decision on what areas to designate as critical habitat. We have developed a draft economic analysis and environmental assessment for the proposal to designate certain areas as critical habitat for the Preble's meadow jumping mouse. We solicit data and comments from the public on these draft documents, as well as on all aspects of the proposal. We may revise the proposal, or its supporting documents, to incorporate or address new information received during the comment period. In particular, we may exclude an area from critical habitat if we determine that the benefits of excluding the area outweigh the benefits of including the area as critical habitat, provided such exclusion will not result in the extinction of the species.

Public Comments Solicited

We intend any final action resulting from this proposal to be as accurate and as effective as possible. Therefore, we solicit comments or suggestions from the public, other concerned governmental agencies, the scientific community, industry, or any other interested party concerning this proposed rule. We do not anticipate extending or reopening the comment period on the proposed rule after the comment period extension provided in this document ends (see **DATES**). We particularly seek comments concerning:

(1) The likely economic and other impacts on farming and ranching in Wyoming and Colorado;

(2) Costs of developing and implementing Habitat Conservation Plans for the Preble's meadow jumping mouse;

(3) Are data available to better model residential growth patterns in Boulder, Douglas, El Paso, Jefferson, Larimer, and Weld Counties, Colorado?

(4) Are data available to better model the characteristics of future developments?

(5) Are data available to better model administrative and project modification costs to developers and private landowners?

(6) Are data available to develop more accurate estimates of the number of future consultations, project modifications, and the costs for the following activities:

(i) Farm Service Agency (FSA) funding for agriculture operational improvements;

(ii) Natural Resource Conservation Service/FSA funding for voluntary conservation programs;

(iii) Grazing leases on Bureau of Land Management lands;

(iv) Utility projects, such as projects requiring a Clean Water Act section 404 permit from the Army Corps of Engineers and Federal Energy Regulatory Commission licensing of natural gas pipelines;

(v) Bank stabilization projects;

(vi) Development and implementation of Habitat Conservation Plans;

(vii) Dam/reservoir projects; and

(viii) Gravel mining projects?

(7) Specific information on additional land use practices, and current or planned activities in proposed critical habitat areas, as well as the anticipated impact of the proposed critical habitat designation on these activities.

We are also continuing to accept comments on the proposed critical habitat designation. If you wish to comment, you may submit your comments and materials concerning this proposal by any one of several methods (see **ADDRESSES**). If you would like to submit comments by electronic format, please submit them in ASCII file format and avoid the use of special characters and encryption. Please include your name and return e-mail address in your e-mail message.

Comments previously submitted need not be resubmitted as they have already been incorporated into the public record and will be fully considered in the final rule. Comments submitted during this comment period also will be incorporated into the public record and will be fully considered in the final rule. In order to comply with the terms of a settlement agreement, we are required to complete the final designation of critical habitat for the Preble's meadow jumping mouse by June 4, 2003 (Civil Action Number 00–D–1180). To meet this date, all comments or proposed revisions to the proposed rule, associated draft economic analysis, and environmental assessment need to be submitted to us during the comment period reopened by this document (see **DATES**).

Our practice is to make comments, including names and home addresses of respondents, available for public review during regular business hours. Individual respondents may request that we withhold their home address, which we will honor to the extent allowable by law. If you wish us to withhold your name or address, you must state this request prominently at the beginning of your comments. However, we will not consider anonymous comments. To the extent consistent with applicable law, we will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public inspection in their entirety. Comments and materials received will be available for public inspection, by appointment, during normal business hours at the above address.

Comments and materials received, as well as supporting documentation used in preparation of the proposal to designate critical habitat, will be available for public inspection, by appointment, during normal business hours at the Colorado Field Office (see **ADDRESSES**).

Author

The primary author of this notice is the Colorado Field Office staff (see **ADDRESSES**).

Authority

The authority for this action is the Endangered Species Act of 1973 (16 U.S.C. 1531 *et seq.*).

Dated: January 22, 2003.

Craig Manson,

Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 03–1803 Filed 1–27–03; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 600

[Docket No. 020424095–2095–01; I.D. 032801B]

RIN 0648–AP25

Fishing Capacity Reduction Program for the Crab Species Covered by the Fishery Management Plan for the Bering Sea/Aleutian Islands King and Tanner Crabs

AGENCY: National Marine Fisheries Service, National Oceanic and Atmospheric Administration, Commerce.

ACTION: Extension of public comment period on proposed rule.

SUMMARY: This document extends for 30 days the public comment period on a proposed rule for establishing a fishing capacity reduction program for the crab species managed under the Bering Sea/Aleutian Islands King and Tanner Crab Fishery Management Plan (FMP), as published on December 12, 2002.

DATES: Comments on the proposed rule will be accepted until February 27, 2003.

ADDRESSES: Mail or fax written comments about this extension or the proposed rule to Michael L. Grable. The mailing address is: Michael L. Grable, Chief, Financial Services Division, National Marine Fisheries Service, 1315 East-West Highway, Silver Spring, MD 20910–3282. The fax number is (301) 713–1306. NMFS will not accept e-mail or internet comments.

If a comment involves any aspect of the proposed rule's collection of information requirements, send the comment both to Michael L. Grable and to the National Oceanic and Atmospheric Administration Desk Officer, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. Anyone may obtain, from Michael L. Grable, the Environmental Assessment, Regulatory Impact Review, and Initial Regulatory Flexibility Analysis for this proposed rule.

Anyone wishing to contact the Restricted Access Management Program (which issues crab species fishing licenses) may do so at this address: Restricted Access Management Program, National Marine Fisheries Service, P.O. Box 21668, Juneau AK 99802–1668. The fax number is (907) 586–7354.

FOR FURTHER INFORMATION CONTACT: Michael L. Grable,(301)713–2390

SUPPLEMENTARY INFORMATION:

Background

On December 12, 2002 (67 FR 76329), NMFS published a proposed rule in the **Federal Register** that would implement regulations for a program to reduce excess capacity and promote economic efficiency in the crab fishery under the FMP. NMFS would finance the voluntary program's $100 million cost with a 30–year loan to be repaid by post-reduction fishermen. The proposed rule was corrected in the **Federal Register** on December 30, 2002 (67 FR 79550).

The deadline for comments on the proposed rule was January 27, 2003, and January 29, 2003 on the correction. This extension of the comment period until February 27, 2003 is in response to requests made by the public. Moreover, as the Bering Sea and Aleutian Islands C. opilio fishery was open during part of the original comment period, NMFS notes that an extension of comment period would give these members of the affected public a better chance to comment on the rule.

Authority: 16 U.S.C. 1801 et. seq.

Dated: January 23, 2003.

Rebecca Lent,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

[FR Doc. 03–1908 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 660

[ID.010303C]

Fisheries Off West Coast States and in the Western Pacific;Pacific Coast Groundfish Fishery; Application for an Exempted Fishing Permit

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of receipt of three exempted fishing permits (EFP) applications; request for comments.

SUMMARY: NMFS announces the receipt of three EFP applications from the Washington State Department of Fish and Wildlife. If awarded, these EFPs would allow vessels with valid Washington State delivery permits to harvest and retain federally managed groundfish in closed rockfish conservation areas and to retain federally managed groundfish species in excess of cumulative trip limits. These activities are otherwise prohibited. Vessels fishing under these EFPs will be required to carry either a State-sponsored sampler or a Federal observer while conducting EFP fishing. Samplers/observers will collect catch and effort data and retain specimens from catch that is generally discarded at sea and is otherwise not available at the shoreside processing facility. These EFP proposals are intended to promote the objectives of the Pacific Coast Groundfish Fishery Management Plan (FMP) by providing much needed data on total catch and incidental catch rates by fishing strategy.

DATES: Comments must be received by February 12, 2003.

ADDRESSES: Copies of the EFP applications are available from Becky Renko Northwest Region, NMFS, 7600 Sand Point Way N.E., Bldg. 1, Seattle, WA 98115–0070.

FOR FURTHER INFORMATION CONTACT: Becky Renko (206)526–6110 or Carrie Nordeen (206) 526–6144.

SUPPLEMENTARY INFORMATION: This action is authorized by the FMP and implementing regulations at 50 CFR 600.745 and 50 CFR 660.350.

On December 12, 2002, NMFS received three completed EFP applications from the Washington State Department of Fish and Wildlife. The primary purpose of the exempted fishing activity is to measure bycatch rates for overfished and other rockfish species associated with the fishing strategies currently used to harvest dogfish shark, walleye pollock, and arrowtooth flounder.

Each EFP requires that the participating vessels carry a State-sponsored sampler or Federal groundfish observer to collect data from which incidental catch rates and total catch of various species and species groups can be estimated. Samplers/observers would also collect and retain specimens, that may not be kept under current regulations. Because the retention of such fish is prohibited by Federal regulations, an EFP is needed to allow State-sponsored samplers to retain these specimens. To the extent possible, data provided by the State-sponsored samplers will be compatible with that collected by the NMFS coastwide observer program. The information gathered through these EFPs may lead to future rulemakings.

At the Pacific Fishery Management Council's (Council) November 2002, meeting in Foster City, CA, the applicants presented the EFP applications. The Council considered the applications and recommended that NMFS issue the EFPs for the proposed activity. All EFP harvests are expected to be within set asides optimum yields (OYs) for 2003 EFP harvests and, therefore, no OY is expected to be exceeded. Copies of the applications are available for review from NMFS (see **ADDRESSES**).

Spiny Dogfish (*Squalus acanthias*)

Spiny dogfish is an abundant and important species in the groundfish fishery off Washington State. Fixed gear is used to directly harvest spiny dogfish. For 2003, fishing with fixed gear in areas where spiny dogfish have historically been harvested will be prohibited because the areas fall within the Non-trawl Rockfish Conservation Area. Rockfish conservation areas are large-scale depth-related areas where low abundance groundfish species are commonly found. Little is known about the bycatch catch rates of other groundfish, including overfished species, by vessels specifically targeting spiny dogfish. However, fishers believe that spiny dogfish can be harvested with much lower bycatch rates than are currently assumed.

If the permit is issued, this EFP will allow approximately 3 vessels, which have historically harvested spiny dogfish, to use fixed gear to directly harvest spiny dogfish and to retain and land groundfish in excess of trip limits taken in a Non-trawl Rockfish Conservation Area. These activities are otherwise prohibited by Federal regulations. Fishing under the proposed EFP would occur between February 1 and May 31, 2003. Vessels would be required to retain all groundfish and the proceeds from the sale of groundfish in excess of current trip limits, other than spiny dogfish, would be forfeited to the State of Washington. All fishing by participating vessels, EFP and non-EFP fishing, during the effective dates of the EFP would be restricted to waters north of 46°16′N. lat.

There will be no monthly limit on the harvest of spiny dogfish, but the harvest of spiny dogfish will be constrained by limits for yelloweye and canary rockfish. If any of the individual limits are reached for an overfished species, the EFP will be terminated. If a permitted vessel harvests 125 lbs (56.7 kg) of canary rockfish or 500 lbs (227 kg) of yelloweye rockfish, the vessels cannot fish in the Non-trawl Rockfish Conservation Area for the rest of that month.

Data collected during this project are expected to have a broad significance to the management of the groundfish fishery by providing much needed information on: (1) total catch by vessels directly harvesting spiny dogfish, (2) catch rates of incidentally caught species, including canary, yelloweye and other rockfish by fishing location, (3) age structure data that is otherwise not available, and (4) the feasibility of a full retention program.

Walleye Pollock (*Theragra chalcogramma*)

In July 2002, three vessels used midwater trawl gear to harvest walleye pollock off the northern coast of Washington State. The walleye pollock stock is primarily found off the west coast of Vancouver island. However, harvestable amounts of walleye pollock move south into Washington waters every 5 to 7 years. Historical harvests of walleye pollock occurred in the area which was designated as the Trawl Rockfish Conservation Area in the 2003 emergency rule (68 FR 544, January 6, 2003). When fishers harvest walleye pollock, which is not a groundfish, they incidentally encounter groundfish such as Pacific whiting, yellowtail rockfish and spiny dogfish.

An EFP is necessary to allow walleye pollock vessels to fish within the Trawl Rockfish Conservation Area with midwater trawl gear and to delay complete sorting of their catch until the point of offloading. An EFP is needed to delay sorting because regulations prohibit the retention of groundfish (except spiny dogfish) taken in a closed area or the retention of groundfish in excess of cumulative trip limits if taken outside the conservation areas.

If the permit is issued, approximately 3 vessels are expected to fish under this EFP. Vessels would be required to retain all groundfish, except spiny dogfish, and the proceeds from the sale of groundfish landed in excess of trip limits would be forfeited to the State of Washington. Fishing under the proposed EFP would occur between February 1 and June 30, 2003. All fishing by participating vessels, EFP and non-EFP fishing, during the effective dates of the EFP would be restricted to waters north of 46°16′ N. lat.

There will be no monthly limit on the harvest of walleye pollock, but the harvest of pollock will be constrained by limits for widow and canary rockfish. If any of the individual limits are reached for an overfished species, the EFP will be terminated.

Data collected during this project are expected to have a broad significance to the management of the groundfish fishery by providing much needed information on: (1) total catch of groundfish in the walleye pollock fishery, (2) catch rates of incidentally caught groundfish species by fishing location, and (3) the feasibility of a full retention program.

Arrowtooth Flounder (*Atheresthes stomias*)

Fishing for arrowtooth flounder, which is an abundant and commercially important groundfish species off Washington, is constrained by efforts to rebuild canary rockfish, an overfished species. Fishers who have historically targeted arrowtooth flounder believe that the fishery can be prosecuted with a much lower rockfish bycatch rate than is currently assumed. Similar EFPs, that yielded valuable data on the arrowtooth flounder fishery, were issued in 2001 and 2002.

If the permit is issued, this EFP would allow approximately 6 vessels, which have historically participated in the arrowtooth flounder fisheries to: fish for arrowtooth flounder within a restricted rockfish conservation area; retain groundfish taken within a rockfish conservation area; and retain and sell arrowtooth flounder and petrale sole in excess of cumulative trip limits. These activities are otherwise prohibited by Federal regulations. Other than the proceeds from the sale of arrowtooth flounder and petrale sole, proceeds from the sale of rockfish in excess of current trip limits would be forfeited to the State of Washington.

There will be no monthly limit on the harvest of arrowtooth flounder, but the harvest of arrowtooth flounder will be constrained by canary rockfish. If any of the individual limits are reached for an overfished species, the EFP will be terminated.

Fishing under the proposed EFP would occur between May 1 and August 31, 2003. All fishing by participating vessels, EFP and non-EFP fishing, during the effective dates of the EFP would be restricted to waters north of 46°16′ N. lat.

Data collected during this project are expected to have a broad significance to the management of the groundfish fishery by providing much needed information on: (1) total catch in the northern flatfish fisheries, (2) catch rates of incidentally caught species, including canary, yelloweye and darkblotched rockfish by fishing location, and (3) age structure data that is otherwise not available.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: January 22, 2003.

Richard W. Surdi,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service

[FR Doc. 03–1909 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–22–S

Notices

Federal Register

Vol. 68, No. 18

Tuesday, January 28, 2003

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.

AGENCY FOR INTERNATIONAL DEVELOPMENT

Notice of Public Information Collection Requirements Submitted to OMB for Review

SUMMARY: U.S. Agency for International Development (USAID) has submitted the following information collection to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. Comments regarding this information collection are best assured of having their full effect if received within 30 days of this notification. Comments should be addressed to: Desk Officer for USAID, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Washington, DC 20503. Copies of submission may be obtained by calling (202) 712–1365.

SUPPLEMENTARY INFORMATION:

OMB Number: OMB 0412–0014

Form Number: AID 1550–6

Title: Voluntary Agency Quarterly Report of Shipping Activity.

Type of Submission: Renewal of Information Collection.

Purpose: The U.S. Agency for International Development's Ocean Freight program reimburses approved Private and Voluntary Organizations (PVOs) registered with the Agency for their transportation costs incurred when transporting donated goods overseas. To effectively monitor the program, USAID has developed a proposal solicitation package and a monitoring document to collect necessary information from qualified and interested PVOs.

Annual Reporting Burden:

Respondents: 50.

Total annual responses: 200.

Total annual hours requested: 3,200 hours.

Dated: January 22, 2003.

Joanne Paskar,

Chief, Information and Records Division, Office of Administrative Services, Bureau for Management.

[FR Doc. 03–1855 Filed 1–27–03; 8:45 am]

BILLING CODE 6116–01–M

AGENCY FOR INTERNATIONAL DEVELOPMENT

Notice of Meeting

Pursuant to the Federal Advisory Committee Act, notice is hereby given of a meeting of the Advisory Committee on Voluntary Foreign Aid (ACVFA).

Date: February 11, 2003 (8:30 a.m. to 5 p.m.).

Location: National Press Club, 529 14th St., NW., 13th Floor, Washington, DC.

This meeting will feature discussion of public diplomacy and foreign aid in the national interest, including the report ''Foreign Aid in the National Interest'' just issued by the U.S. Agency for International Development. Participants will have an opportunity to ask questions of the speakers and to discuss the issues in more depth in small groups.

The meeting is free and open to the public. Persons wishing to attend the meeting can fax or e-mail their name to Brenda Jackson, 202–347–9212, *pvcsupport@datexinc.com.*

Dated: January 28, 2003.

Noreen O'Meara,

Executive Director, Advisory Committee on Voluntary Foreign Aid (ACVFA).

[FR Doc. 03–1856 Filed 1–27–03; 8:45 am]

BILLING CODE 6116–01–P

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

[Docket No. 03–003–1]

Availability of an Environmental Assessment for Field Testing West Nile Virus Vaccine

AGENCY: Animal and Plant Health Inspection Service, USDA

ACTION: Notice.

SUMMARY: We are advising the public that the Animal and Plant Health Inspection Service has prepared an environmental assessment concerning authorization to ship for the purpose of field testing, and then to field test, an unlicensed West Nile Virus Vaccine for use in horses. The environmental assessment, which is based on a risk analysis prepared to assess the risks associated with the field testing of this vaccine, examines the potential effects that field testing this veterinary vaccine could have on the quality of the human environment. Based on the risk analysis, we have reached a preliminary determination that field testing this veterinary vaccine will not have a significant impact on the quality of the human environment, and that an environmental impact statement need not be prepared. We intend to authorize shipment of this vaccine for field testing following the close of the comment period for this notice unless new substantial issues bearing on the effects of this action are brought to our attention. We also intend to issue a U.S. Veterinary Biological Product license for this vaccine, provided the field test data support the conclusions of the environmental assessment and the issuance of a finding of no significant impact and the product meets all other requirements for licensure.

DATES: We will consider all comments that we receive on or before February 27, 2003.

ADDRESSES: You may submit comments by postal mail/commercial delivery or by e-mail. If you use postal mail/commercial delivery, please send four copies of your comment (an original and three copies) to: Docket No. 03–003–1, Regulatory Analysis and Development, PPD, APHIS, Station 3C71, 4700 River Road Unit 118, Riverdale, MD 20737–1238. Please state that your comment refers to Docket No. 03–003–1. If you use e-mail, address your comment to *regulations@aphis,usda.gov.* Your comment must be contained in the body of your message; do not send attached files. Please include your name and address in your message and ''Docket No. 03–003–1'' on the subject line.

You may read the environmental assessment, the risk analysis (with confidential business information removed), and any comments that we receive in our reading room. The reading room is located in room 1141 of the USDA South Building, 14th Street and Independence Avenue, SW., Washington, DC. Normal reading room

hours are 8 a.m. to 4:30 p.m., Monday through Friday, except holidays. To be sure someone is there to help you, please call (202) 690–2817 before coming.

You may request a copy of the environmental assessment (as well as the risk analysis with confidential business information removed) by writing to Dr. Larry R. Ludemann, USDA, APHIS, VS, CVB–LPD, 510 South 17th Street, Suite 104, Ames, IA 50010, or by calling (515) 232–5785. Please refer to the docket number, date and complete title of this of this notice when requesting copies.

APHIS documents published in the **Federal Register,** and related information, including the names of organizations and individuals who have commented on APHIS dockets, are available on the Internet at *http://www.aphis.usda.gov/ppd/rad/webrepor.html.*

FOR FURTHER INFORMATION CONTACT: Dr. Albert P. Morgan, Chief Staff Officer, Operational Support Section, Center for Veterinary Biologics, Licensing and Policy Development, VS, APHIS, USDA, 4700 River Road Unit 148 , Riverdale, MD 20737–1231; phone (301) 734–8245; fax (301) 734–4314. For information regarding the environmental assessment or the risk analysis, contact Dr. Larry R. Ludemann, USDA, APHIS, VS, CVB–LPD, 510 South 17th Street, Suite 104, Ames, IA 50010; (515) 232–5785.

SUPPLEMENTARY INFORMATION: Under the Virus-Serum-Toxin Act (21 U.S.C. 151 *et seq.*), a veterinary biological product must be shown to be pure, safe, potent, and efficacious before a veterinary biological product license may be issued. A field test is generally necessary to satisfy prelicensing requirements for veterinary biological products. Prior to conducting a field test on an unlicenced product, an applicant must obtain approval from the Animal and Plant Health Inspection Service (APHIS), as well as obtain APHIS' authorization to ship the product for field testing.

To determine whether to authorize shipment and grant approval for the field testing of the unlicenced product referenced in this notice, APHIS conducted a risk analysis to assess the potential effects of this product on the safety of animals, public health, and the environment. Based on the risk analysis, APHIS has prepared an environmental assessment (EA) concerning the field testing of the following unlicenced veterinary biological product:

Requester: Fort Dodge Animal Health, Inc.

Product: West Nile Virus Vaccine, DNA Vaccine, Code 1995.D0.

Field Test Locations: California, Kansas, Kentucky, Maryland, Ohio, and Oklahoma.

The above-mentioned product is an *Esherichia coli* plasmid containing the prM and E genes of the West Nile virus. The vaccine is for use in horses as an aid in the prevention of viremia associated with West Nile virus infection.

The EA has been prepared in accordance with: (1) The National Environmental Policy Act of 1969 (NEPA), as amended (42 U.S.C. 4321 *et seq.*), (2) regulations of the Council on Environmental Quality for implementing the procedural provision of NEPA (40 CFR parts 1500–1508), (3) USDA regulations implementing NEPA (7 CFR part 1b), and (4) APHIS' NEPA Implementing Procedures (7 CFR part 372).

Unless substantial issues with adverse environmental impacts are raised in response to this notice, APHIS intends to issue a finding of no significant impact (FONSI) based on the EA and authorize shipment of the above product for the initiation of field tests following the close of the comment period for this notice.

Because the issues raised by field testing and by issuance of a license are identical, APHIS has concluded that the EA that is generated for field testing would also be applicable to the proposed licensing action. Provided that the field test data support the conclusions of the original EA and the issuance of a FONSI, APHIS does not intend to issue a separate EA and FONSI to support the issuance of the product license, and would determine that an environmental impact statement need not be prepared. APHIS intends to issue a veterinary biological product license for this vaccine following completion of the field test provided no adverse impacts on the human environment are identified and provided the product meets all other requirements for licensure.

Authority: 21 U.S.C. 151–159.

Done in Washington, DC, this 22nd day of January, 2003.

Bobby R. Acord,

Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 03–1864 Filed 1–27–03; 8:45 am]

BILLING CODE 3410–34–M

DEPARTMENT OF AGRICULTURE

Forest Service

Record of Decision on the Woodpecker Project Area Final Environmental Impact Statement

AGENCY: Forest Service, USDA.

ACTION: Notice; record of decision.

SUMMARY: The USDA Forest Service, Tongass National Forest, has prepared the record of decision for the Woodpecker Project Area. The project area is located within the Petersburg Ranger District, on Mitkof Island, about 27 miles south of Petersburg, Alaska. Thomas Puchlerz, Forest Supervisor for the Tongass National Forest, has selected a modification of Alternative 6 from the final Environmental Impact Statement (final EIS, August 2001). This decision includes: (a) Harvest of approximately 5.4 million board feet of timber from approximately 400 acres, (b) parking turnouts, (c) improvement of dispersed recreation use areas, (d) closure of approximately ten miles of existing road for watershed improvement, and (e) adjustment of three small old-growth habitat reserves. Approximately 2.5 miles of temporary road will be constructed to access the timber. No new classified road designed for long-term use will be constructed. An existing log transfer facility will be used.

DATES: The legal notice of this decision was published in the *Juneau Empire,* the newspaper of record, published in Juneau, Alaska, on January 23, 2003. This began the 45-day appeal period, which will close on Monday, March 10, 2003. This decision may be implemented no sooner than 5 business days after close of the appeal period, if no appeal is received. If an appeal is received, this decision may be implemented no sooner than 15 days following disposition of the appeal.

ADDRESSES: Requests for copies of the record of decision of final EIS may be directed to: Cynthia Sever, Petersburg Ranger District, P.O. Box 1328, Petersburg, Alaska 99833, Phone (907) 772–3871; fax (907) 772–5995; or e-mail *csever@fs.fed.us.* The Responsible Official is Thomas Puchlerz, Forest Supervisor, Tongass National Forest, 648 Mission Street, Ketchikan, AK 99901. The Regional Forester is the Appeal Deciding Officer. Written notices of appeal must be addressed to: Regional Forester, Alaska Region, USDA, Forest Service, P.O. Box 21628, Juneau, AK 99802–1628.

FOR FURTHER INFORMATION CONTACT: Requests for further information

concerning the final EIS or the record of decision may be directed to Patricia Grantham, District Ranger, or Cynthia Sever, Interdisciplinary Team Leader, Petersburg Ranger District, 907–772–3871. Copies of the record of decision have been mailed directly to those people who requested to be on the project mailing list. Additional copies may be obtained from the Petersburg Ranger District or reviewed at public libraries throughout southeast Alaska. The record of decision is also posted on the Tongass National Forest website at *www.fs.fed.us/r10/tongass.*

SUPPLEMENTARY INFORMATION: *Background:* The August 13, 2001 record of decision for the Woodpecker Project Area was reversed on appeal because of some data discrepancies in the final EIS. A supplemental information report was prepared to determine whether these discrepancies influenced the effects analysis. This review concluded that only minor changes to information in the final EIS were necessary, and that the analysis presented in the final EIS was valid. The modifications to Alternative 6 for this record of decision were made to comply with the injunction issued on April 26, 2002, by the U.S. District Court, District of Alaska, in *Sierra Club* v. *Rey* (J00–0009 CV (JKS)). The Selected Alternative includes timber harvest and road construction only within roaded areas, as defined by the court. This decision is subject to administrative review (appeal) pursuant to 36 CFR part 215. The legal notice of this decision was published in the *Juneau Empire,* the newspaper of record, published in Juneau, Alaska, on January 23, 2003. The 45-day appeal filing period will close on Monday, March 10, 2003. A written notice of appeal that includes sufficient evidence of why this decision should be changed and requirements of 36 CFR part 215 must be postmarked by this date and filed with the Appeal Deciding Officer: Regional Forester, Alaska Region, USDA Forest Service, PO Box 21628, Juneau, AK 99802–1628.

Responsible Official: Thomas Puchlerz, Forest Supervisor, Tongass National Forest, Federal Building, Ketchikan, Alaska 99901, is the responsible official.

(Authority: 40 CFR 1505.2 and 1506.6; Forest Service Handbook 1909.15, section 28)

Dated: January 21, 2003.

Thomas Puchlerz,

Forest Supervisor.

[FR Doc. 03–1822 Filed 1–27–03; 8:45 am]

BILLING CODE 3410–11–M

DEPARTMENT OF AGRICULTURE

Forest Service

Notice of Mineral County Resource Advisory Committee Meeting

AGENCY: Forest Service, USDA.

ACTION: Notice of meeting.

SUMMARY: Pursuant to the authorities in the Federal Advisory Committee Act (Pub. L. 92–463) and under the Secure Rural Schools and Community Self-Determination Act of 2000 (Pub. L. 106–393) the Lolo National Forest's Mineral County Resource Advisory Committee will meet on February 4 and March 4 at 6 p.m. until 8 p.m. in Superior, Montana for a business meeting. The meeting is open to the public.

DATES: February 4, 2003, and March 4, 2003.

ADDRESSES: The meeting will be held at the Mineral County Courthouse, 300 River Street, Superior, MT 59872.

FOR FURTHER INFORMATION CONTACT: Robert Harper, Designated Forest Official (DFO), District Ranger, Superior District, Lolo National Forest at (406) 822–4233.

SUPPLEMENTARY INFORMATION: Agenda topics for these meeting include the presentation of new project proposals and selection of proposals. If the meeting location is changed, notice will be posted in local newspaper, including the Mineral Independent and the Missoulian.

Dated: January 21, 2003.

Deborah L. R. Austin,

Designated Federal Official.

[FR Doc. 03–1806 Filed 1–27–03; 8:45 am]

BILLING CODE 3410–11–M

DEPARTMENT OF AGRICULTURE

Natural Resources Conservation Service

Notice of Intent to Write an Environmental Impact Statement (EIS) for Williamson River Delta Restoration Project

AGENCY: Natural Resources Conservation Service, USDA.

ACTION: Notice of intent to write an Environmental Impact Statement (EIS) for the Williamson River Delta Restoration Project and requesting public comment. A public meeting will be held at the Chiloquin High School Library on January 28, 2003, at 7 p.m. (*see* Web site below for more information).

SUMMARY: The NRCS is seeking public comment for the next phase of the stream restoration project on the Williamson River Delta. The full notice of intent can be found at the following website: *http://www.or.nrcs.usda.gov.*

DATES: Comments will be received for a 45-day period beginning January 29, 2003, through March 15, 2003.

ADDRESSES: Address all requests and comments to Kevin Conroy, Basin Team Leader, Natural Resources Conservation Service (NRCS), 2316 South 6th St., Suite C, Klamath Falls, OR 97601, 541–882–9044 (FAX).

FOR FURTHER INFORMATION CONTACT: Kevin Conroy, 541–883–6924.

Dated: January 22, 2003.

Bob Graham,

State Conservationist, Portland, OR.

[FR Doc. 03–1885 Filed 1–27–03; 8:45 am]

BILLING CODE 3410–16–P

DEPARTMENT OF AGRICULTURE

Rural Housing Service

Notice for Requests for Proposals for Guaranteed Loans Under the Section 538 Guaranteed Rural Rental Housing Program (GRRHP) for Fiscal Year 2003; Correction

AGENCY: Rural Housing Service, USDA.

ACTION: Notice; correction.

SUMMARY: The Rural Housing Service (RHS) is correcting a notice published December 27, 2002 (67 FR 79038–79042). This action is taken to add a priority criteria for the selection of projects requesting interest credit assistance and increase the threshold score for the interest credit award.

Accordingly, the notice published December 27, 2002 (67 FR 79038–79042), is corrected as follows:

On page 79039 in the second column, fifth full paragraph, revise the number ''55'' to read ''65''.

On page 79041 in the first column, second paragraph, revise the word ''six'' to read ''seven''.

On page 79041 in the third column after the second full paragraph, add the following:

''*Priority 7*—RHS will award points for interest rates charged above the applicable federal rate at the time of loan closing as follows:

Interest rate	Points
More than 250 basis points	−20
200 to 250 basis points, inclusive	5
100 to 199 basis points, inclusive	10
0 to 99 basis points, inclusive	15

.''

Dated: January 16, 2003.

Arthur A. Garcia,

Administrator, Rural Housing Service.

[FR Doc. 03–1833 Filed 1–27–03; 8:45 am]

BILLING CODE 3410–XV–P

DEPARTMENT OF COMMERCE

Foreign-Trade Zones Board

[Docket 2–2003]

Foreign-Trade Zone 14—Little Rock, Arkansas, Application for Subzone, Lion Oil Co., (Oil Refinery), El Dorado, AR

An application has been submitted to the Foreign-Trade Zones Board (the Board) by the Arkansas Department of Economic Development, grantee of FTZ 14, requesting special-purpose subzone status for the oil refining facilities of Lion Oil Company (Lion), located in El Dorado, Arkansas. The application was submitted pursuant to the provisions of the Foreign-Trade Zones Act, as amended (19 U.S.C. 81a–81u), and the regulations of the Board (15 CFR part 400). It was formally filed on January 15, 2003.

The refinery complex (65,000 BPD capacity, 651,000 barrel storage capacity) consists of three sites in Union and Columbia Counties, Arkansas: Site 1 (407 acres)—main refinery complex, and Sand Hill Terminal located at 1000 McHenry Avenue, El Dorado; Site 2 (26 acres)—Amoco Station storage facility, located on American Road in El Dorado; Site 3 (42 acres)—Magnolia Station storage facility, located on Highway 25 in Magnolia. The refinery (412 employees) is used to produce fuels and other petroleum products. Products include gasoline, diesel, distillates, propane, propane/propylene mix, asphalts and sulfur. Some 60 percent of the crude oil (96 percent of inputs) is sourced abroad.

Zone procedures would exempt the refinery from Customs duty payments on the foreign products used in its exports. On domestic sales, the company would be able to choose the Customs duty rates that apply to certain petroleum products and refinery by-products (duty-free) by admitting incoming foreign crude in non-privileged foreign status. The duty rates on inputs range from 5.25 cents/barrel to 10.5 cents/barrel. The application indicates that the savings from zone procedures would help improve the plant's international competitiveness.

In accordance with the Board's regulations, a member of the FTZ staff has been appointed examiner to investigate the application and report to the Board. Public comment is invited from interested parties. Submissions (original and 3 copies) shall be addressed to the Board's Executive Secretary at one of the following addresses:

1. Submissions Via Express/Package Delivery Services: Foreign-Trade-Zones Board, U.S. Department of Commerce, Franklin Court Building—Suite 4100W, 1099 14th St. NW., Washington, DC 20005; or

2. Submissions Via the U.S. Postal Service: Foreign-Trade-Zones Board, U.S. Department of Commerce, FCB—Suite 4100W, 1401 Constitution Ave. NW., Washington, DC 20230.

The closing period for their receipt is March 31, 2003. Rebuttal comments in response to material submitted during the foregoing period may be submitted during the subsequent 15-day period (to April 14, 2003).

A copy of the application and accompanying exhibits will be available for public inspection at the Office of the Foreign-Trade Zones Board's Executive Secretary at the first address listed above, and at the U.S. Department of Commerce Export Assistance Center, 425 West Capital Avenue, Suite 700, Little Rock, AR 72201.

Dated: January 16, 2003.

Dennis Puccinelli,

Executive Secretary.

[FR Doc. 03–1904 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

Foreign-Trade Zones Board

[Order No. 1264]

Grant of Authority for Subzone Status, Deepsea Flexibles, Inc., Galveston, Texas; Correction

The **Federal Register** notice (68 FR 2313, 1/16/03) describing Foreign-Trade Zones Board Order 1264, authorizing special-purpose subzone status for the Deepsea Flexibles, Inc. facility in Galveston, Texas (Subzone 36A), is corrected as follows:

Paragraph 8 should read ''Signed at Washington, DC, this 8th day of January, 2003.''

Dated: January 16, 2003.

Dennis Puccinelli,

Executive Secretary.

[FR Doc. 03–1903 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

National Infrastructure Advisory Council; Notice of Open Meeting

The National Infrastructure Advisory Council (NIAC) will meet on Friday, February 7, 2003, at 12 p.m.–1:30 p.m. The meeting will be open to public access via conference call. Members of the public interested in attending by telephone should call (toll free) 1–888–899–7785 or (toll) 1–913–312–4169 and, when prompted, enter pass code 1468517.

The Council advises the President of the United States on the security of information systems for critical infrastructure supporting other sectors of the economy, including banking and finance, transportation, energy, manufacturing, and emergency government services.

Agenda

I. Introduction of NIAC Members.

II. Welcoming remarks—Richard Clarke, Special Advisor to the President for Cyberspace Security; Executive Director, NIAC.

III. Welcoming remarks—Richard Davidson, Chairman, NIAC.

IV. Discussion of future topics for study:

a. Internet Protocol Version 6.0.

b. Responsible disclosure of cyber attacks/incidents.

V. Comments.

VI. Adjournment.

Written comments may be submitted at any time before or after the meeting. However, to facilitate distribution of public presentation materials to Council members, the Council suggests that presenters forward the public presentation materials, ten days prior to the meeting date, to the following address: Ms. Wanda Rose, Critical Infrastructure Assurance Office, Bureau of Industry and Security, U.S. Department of Commerce, Room 6095, 14th Street & Constitution Avenue, NW., Washington, DC. 20230.

For more information contact Wanda Rose at (202) 482–7481.

Dated: January 21, 2003.

Janice L. Pesgna,

Acting Council Liaison Officer.

[FR Doc. 03–1779 Filed 1–24–03; 9:43 am]

BILLING CODE 3510–JT–M

DEPARTMENT OF COMMERCE

International Trade Administration

[A-570–873]

Notice of Amended Final Antidumping Duty Determination of Sales at Less Than Fair Value and Antidumping Duty Order: Ferrovanadium From the People's Republic of China

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

ACTION: Notice of Amended Final Antidumping Duty Determination of Sales at Less Than Fair Value and Antidumping Duty Order.

SUMMARY: We are amending our final determination (*See Notice of Final Determination of Sales at Less Than Fair Value: Ferrovanadium from the People's Republic of China*, 67 FR 71137 (November 29, 2002) (*Final Determination*)) to reflect the correction of certain ministerial errors. This correction is in accordance with section 735(e) of the Tariff Act of 1930, as amended (the Act), and 19 CFR 351.224. The period of investigation (POI) covered by this amended final determination is April 1, 2001, through September 30, 2001. This notice also constitutes the antidumping duty order with respect to ferrovanadium from the People's Republic of China (the PRC).

EFFECTIVE DATE: January 28, 2003.

FOR FURTHER INFORMATION CONTACT: Karine Gziryan or Howard Smith; AD/CVD Enforcement, Office 4, Group II, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW, Washington, DC 20230; telephone: (202) 482–4081 and (202) 482–5193, respectively.

SUPPLEMENTARY INFORMATION:

Scope of the Order

The scope of this order covers all ferrovanadium regardless of grade, chemistry, form, shape, or size. Ferrovanadium is an alloy of iron and vanadium that is used chiefly as an additive in the manufacture of steel. The merchandise is commercially and scientifically identified as vanadium. The scope specifically excludes vanadium additives other than ferrovanadium, such as nitrided vanadium, vanadium-aluminum master alloys, vanadium chemicals, vanadium oxides, vanadium waste and scrap, and vanadium-bearing raw materials such as slag, boiler residues and fly ash. Merchandise under the following Harmonized Tariff Schedule of the United States (HTSUS) item numbers 2850.00.2000, 8112.40.3000, and 8112.40.6000 are specifically excluded. Ferrovanadium is classified under HTSUS item number 7202.92.00. Although the HTSUS item number is provided for convenience and Customs purposes, the Department's written description of the scope of this order remains dispositive.

Amended Final Determination

On November 29, 2002, in accordance with sections 735(d) and 777(i)(1) of the Act, the Department published its affirmative final determination in this proceeding. *See Final Determination*, 67 FR 71137. Pursuant to 19 CFR 351.224(c), on December 5, 2002, the Department received timely filed allegations of ministerial errors in the *Final Determination* from the petitioners[1] and the respondent, Pangang Group International Economic & Trading Corp. (Pangang). The petitioners alleged that the Department inadvertently failed to (1) exclude aberrational data from the calculation of the surrogate value for sulfuric acid, (2) remove all subsidized imports from the import statistics used to calculate the surrogate value for wooden boxes, and (3) accurately convert the unit of measure for Pangang's consumption of nitrogen. Pangang alleged that the Department failed to (1) accurately calculate the surrogate value for barium peroxide and (2) calculate normal value using the correct consumption quantities for the auxiliary materials used to produce FeV_{80}. On December 10, 2002, Pangang filed rebuttal comments in response to the petitioners' allegation of ministerial errors.

We have reviewed the calculations used in the *Final Determination* and find that there are two errors that constitute ministerial errors within the meaning of 19 CFR 351.224(f). For a detailed analysis of the ministerial error allegations and the Department's position on each, *see* Memorandum to Faryar Shirzad, Assistant Secretary for Import Administration, from Bernard T. Carreau, Deputy Assistant Secretary for Import Administration, ''Allegation of Ministerial Errors in the Final Determination,'' dated concurrently with this notice. Pursuant to section 735(e) of the Act, we have amended the *Final Determination* and corrected the following errors: (1) the calculation of the surrogate value for barium peroxide and (2) the auxiliary material consumption quantities for FeV_{80}. Correcting these errors changes Pangang's final antidumping duty margin from 13.03 percent to the margin listed below. We found the petitioners' allegations to involve methodological issues, rather than ministerial errors, and therefore have not adjusted Pangang's final antidumping duty margin based on the petitioners' allegations.

Antidumping Duty Order

On January 13, 2003, in accordance with section 735(d) of the Act, the International Trade Commission (the Commission) notified the Department of its final determination that an industry in the United States is materially injured by reason of less-than-fair-value imports of subject merchandise from the PRC, pursuant to section 735(b)(1)(A) of the Act. Therefore, in accordance with section 736(a)(1) of the Act, the Department will direct the U.S. Customs Service to assess, upon further advice by the Department, antidumping duties equal to the amount by which the normal value of the merchandise exceeds the export price of the merchandise for all relevant entries of ferrovanadium from the PRC. For all producers and exporters, antidumping duties will be assessed on all unliquidated entries of subject merchandise that are entered, or withdrawn from warehouse, for consumption on or after July 8, 2002, the date on which the Department published its notice of affirmative preliminary determination in the **Federal Register**. *See Notice of Preliminary Determination of Sales at Less Than Fair Value and Postponement of Final Determination: Ferrovanadium from the People's Republic of China*, 67 FR 45088 (July 8, 2002).

On or after the date of publication of this notice in the **Federal Register**, the U.S. Customs Service must require, at the same time as importers would normally deposit estimated duties, cash deposits for the subject merchandise equal to the estimated weighted-average dumping margins listed below. The ''PRC-Wide'' rate applies to all exporters of subject merchandise not specifically listed below.

Manufacturer/exporter	Margin (%)
Pangang Group International Economic & Trading Corporation	12.97
PRC-Wide Rate	66.71

[1] The petitioners in this proceeding are the Ferroalloys Association Vanadium Committee (TFA Vanadium Committee) and its members: Bear Metallurgical Company, Shieldalloy Metallurgical Corporation, Gulf Chemical & Metallurgical Corporation, U.S. Vanadium Corporation, and CS Metals of Louisiana LLC.

This notice constitutes the antidumping duty order with respect to ferrovanadium from the PRC. Interested parties may contact the Department's Central Records Unit, Room B-099 of the main Commerce building, for copies of an updated list of antidumping duty orders currently in effect.

This order is issued and published in accordance with section 736(a) of the Act and 19 CFR 351.211.

Dated: January 21, 2003.

Faryar Shirzad,

Assistant Secretary for Import Administration.

[FR Doc. 03–1900 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–DS–S

DEPARTMENT OF COMMERCE

International Trade Administration

[A-791–815]

Notice of Antidumping Duty Order: Ferrovanadium from the Republic of South Africa

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

ACTION: Notice of Antidumping Duty Order: Ferrovanadium from the Republic of South Africa.

EFFECTIVE DATE: January 28, 2003.

FOR FURTHER INFORMATION CONTACT: Mark Manning or Crystal Scherr Crittenden; AD/CVD Enforcement, Office 4, Group II, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–5253 or (202) 482–0989, respectively.

SUPPLEMENTARY INFORMATION:

Scope of the Order

The scope of this order covers all ferrovanadium regardless of grade, chemistry, form, shape, or size. Ferrovanadium is an alloy of iron and vanadium that is used chiefly as an additive in the manufacture of steel. The merchandise is commercially and scientifically identified as vanadium. It specifically excludes vanadium additives other than ferrovanadium, such as nitrided vanadium, vanadium-aluminum master alloys, vanadium chemicals, vanadium oxides, vanadium waste and scrap, and vanadium-bearing raw materials such as slag, boiler residues and fly ash. Merchandise under the following Harmonized Tariff Schedule of the United States (HTSUS) item numbers 2850.00.2000, 8112.40.3000, and 8112.40.6000 are specifically excluded. Ferrovanadium is classified under HTSUS item number 7202.92.00. Although the HTSUS item number is provided for convenience and Customs purposes, the Department's written description of the scope of this order remains dispositive.

Antidumping Duty Order

On January 13, 2003, in accordance with section 735(d) of Tariff Act of 1930, as amended (the Act), the International Trade Commission (the Commission) notified the Department of Commerce (the Department) of its final determination that an industry in the United States is materially injured by reason of less-than-fair-value imports of subject merchandise from South Africa, pursuant to section 735(b)(1)(A) of the Act. Therefore, in accordance with section 736(a)(1) of the Act, the Department will direct the U.S. Customs Service to assess, upon further advice by the Department, antidumping duties equal to the amount by which the normal value of the merchandise exceeds the U.S. price of the merchandise for all relevant entries of ferrovanadium from South Africa. For all producers and exporters, antidumping duties will be assessed on all unliquidated entries of subject merchandise that are entered, or withdrawn from warehouse, for consumption on or after July 8, 2002, the date on which the Department published its notice of affirmative preliminary determination in the **Federal Register**. *See Notice of Preliminary Determination of Sales at Less Than Fair Value and Postponement of Final Determination: Ferrovanadium from the Republic of South Africa*, 67 FR 45083 (July 8, 2002).

On or after the date of publication of this notice in the **Federal Register**, the U.S. Customs Service must require, at the same time as importers would normally deposit estimated duties, cash deposits for the subject merchandise equal to the estimated weighted-average dumping margins listed below. The ''All Others'' rate applies to all exporters of subject merchandise not specifically listed below.

Manufacturer/exporter	Margin (percent)
Highveld Steel and Vanadium Corporation, Ltd.	116.00
Xstrata South Africa (Proprietary) Limited.	116.00
All Others	116.00

This notice constitutes the antidumping duty order with respect to ferrovanadium from the Republic of South Africa. Interested parties may contact the Department's Central Records Unit, Room B-099 of the main Commerce building, for copies of an updated list of antidumping duty orders currently in effect.

This order is issued and published in accordance with section 736(a) of the Act and 19 CFR 351.211.

Dated: January 21, 2003.

Faryar Shirzad,

Assistant Secretary for Import Administration.

[FR Doc. 03–1901 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–DS–S

DEPARTMENT OF COMMERCE

International Trade Administration

[A-588–862]

Notice of Initiation of Antidumping Duty Investigation: High and Ultra-High Voltage Ceramic Station Post Insulators from Japan

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

ACTION: Initiation of Antidumping Duty Investigation.

EFFECTIVE DATE: January 28, 2003.

FOR FURTHER INFORMATION CONTACT: Timothy Finn or Michele Mire at (202) 482–0065 or (202) 482–4711, respectively; Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW, Washington, DC 20230.

Initiation of Investigation

The Petition

On December 31, 2002, the Department of Commerce (the Department) received a petition filed in proper form by Lapp Insulator Company LLC (Lapp), Newell Porcelain Co., Inc. (Newell), Victor Insulators, Inc. (Victor), and the IUE Industrial Division of the Communications Workers of America, the union representing employees of Lapp (collectively, petitioners). The Department received information supplementing the petition on January 14, 2003.

In accordance with section 732(b) of the Tariff Act of 1930, as amended (the Act), the petitioners allege that imports of high and ultra-high voltage ceramic station post insulators from Japan (hereinafter referred to as subject merchandise or station post insulators) are being, or are likely to be, sold in the United States at less than fair value

within the meaning of section 731 of the Act, and that such imports are materially injuring, or are threatening to materially injure, an industry in the United States.

The Department finds that the petitioners filed this petition on behalf of the domestic industry because they are interested parties as defined in sections 771(9)(C) and 771(9)(D) of the Act and have demonstrated sufficient industry support with respect to the antidumping duty investigation that they are requesting the Department initiate (*see* the ''Determination of Industry Support for the Petition'' section below).

Scope of Investigation

The scope of this investigation covers station post insulators manufactured of porcelain, of standard strength,[1] high strength, or extra-high strength, solid core or cavity core, single unit or stacked unit, assembled or unassembled, and with or without hardware attached, rated at 115 kilovolts (kV) voltage class and above (550 kilovolt Basic Impulse Insulation Level (BIL) and above), including, but not limited to, those manufactured to meet the following American National Standards Institute, Inc. (ANSI) standard class specifications: T.R.-286, T.R.-287, T.R.-288, T.R.-289, T.R.-291, T.R.-295, T.R.-304, T.R.-308, T.R.-312, T.R.-316, T.R.-362 and T.R.-391. Subject merchandise is classifiable under subheading 8546.20.0060 of the Harmonized Tariff Schedule of the United States (HTSUS) Annotated. While the HTSUS subheading is provided for convenience and U.S. Customs purposes, the written description above remains dispositive as to the scope of the investigation.[2]

During our review of the petition, we sought additional information from the petitioners concerning the scope of the investigation. As a result of this supplemental information, we modified the scope language proposed by the petitioners with regard to the voltage class of subject merchandise covered. The petitioners proposed that the scope cover subject merchandise rated at greater than 69 kV voltage class and above (350 kV BIL and above). However, the petitioners noted that they do not manufacture station post insulators with service class ratings between 69 kV and 115 kV. Thus, for purposes of this proceeding, we changed the voltage class of covered merchandise to 115 kV and above.

As discussed in the preamble to the Department's regulations (62 FR 27323), we are setting aside a period for parties to raise issues regarding product coverage. The Department encourages all parties to submit such comments by February 10, 2003. Comments should be addressed to the Import Administration's Central Records Unit, Room 1870, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW, Washington, DC 20230. The period of scope consultations is intended to provide the Department with ample opportunity to consider all comments and consult with parties prior to the issuance of the preliminary determination. See the *Import Administration AD Investigation Checklist*, dated January 21, 2003 (*Initiation Checklist*) (public version on file in the Central Records Unit of the Department of Commerce, Room B-099).

Determination of Industry Support for the Petition

Section 771(4)(A) of the Act defines the ''industry'' as the producers of a domestic like product. Thus, to determine whether the petition has the requisite industry support, the statute directs the Department to look to producers and workers who produce the domestic like product. The United States International Trade Commission (ITC), which is responsible for determining whether ''the domestic industry'' has been injured, must also determine what constitutes a domestic like product in order to define the industry. While both the Department and the ITC must apply the same statutory definition regarding domestic like product (see section 771(10) of the Act), they do so for different purposes and pursuant to their separate and distinct authority. In addition, the Department's determination is subject to limitations of time and information. Although this may result in different definitions of the like product, such differences do not render the decision of either agency contrary to the law.[2]

Section 771(10) of the Act defines the domestic like product as ''a product which is like, or in the absence of like, most similar in characteristics and uses with, the article subject to an investigation under this title.'' Thus, the reference point from which the domestic like product analysis begins is ''the article subject to an investigation,'' *i.e.*, the class or kind of merchandise to be investigated, which normally will be the scope as defined in the petition.

In this petition, the petitioners do not offer a definition of domestic like product distinct from the scope of this investigation. Thus, based on our analysis of the information presented to the Department by the petitioners, we have determined that there is a single domestic like product, which is defined in the ''Scope of Investigation'' section above, and have analyzed industry support in terms of this domestic like product.

Section 732(b)(1) of the Act requires that a petition be filed on behalf of the domestic industry. Section 732(c)(4)(A) of the Act provides that a petition meets this requirement if the domestic producers or workers who support the petition account for: (1) at least 25 percent of the total production of the domestic like product; and, (2) more than 50 percent of the production of the domestic like product produced by that portion of the industry expressing support for, or opposition to, the petition. Information contained in the petition demonstrates that the domestic producers or workers who support the petition account for over 50 percent of the total production of the domestic like product. Therefore, the requirements of section 732(c)(4)(A)(i) are met. See *Initiation Checklist*. Furthermore, because the Department received no opposition to the petition, and because the domestic producers or workers who support the petition account for more than 50 percent of the domestic industry, they also account for more than 50 percent of the production of the domestic like product produced by that portion of the industry expressing support for, or opposition to, the petition. See *Initiation Checklist*. Thus, the requirements of section 732(c)(4)(A)(ii) are met.

Accordingly, the Department determines that the petition was filed on behalf of the domestic industry within the meaning of section 732(b)(1) of the Act. See *Initiation Checklist*.

[1] Station post insulators are manufactured in various styles and sizes, and are classified primarily according to the voltage they are designed to withstand. Under the governing industry standard issued by the Institute of Electrical and Electronic Engineers (IEEE), the voltage spectrum is divided into three broad classes: ''medium'' voltage (*i.e.*, less than or equal to 69 kilovolts), ''high'' voltage (*i.e.*, from 115 to 230 kilovolts), and ''extra-high'' or ''ultra-high'' voltage (*i.e.*, greater than 230 kilovolts).

[2] HTSUS subheading 8546.20.00 includes ceramic electrical insulators in general. Station post insulators are classified under HTSUS number 8546.20.0060 which also includes non-subject merchandise.

[3] *See Algoma Steel Corp. Ltd., v. United States*, 688 F. Supp. 639, 642-44 (CIT 1988); *High Information Content Flat Panel Displays and Display Glass Therefore from Japan: Final Determination; Rescission of Investigation and Partial Dismissal of Petition*, 56 FR 32376, 32380-81 (July 16, 1991).

Period of Investigation

The anticipated period of investigation (POI) is October 1, 2001 through September 30, 2002.

Constructed Export Price and Normal Value

The following is a description of the allegation of sales at less than fair value upon which the Department has based its decision to initiate this investigation.

Constructed Export Price

The petitioners identified NGK Insulators, Ltd. (NGK) and its wholly-owned U.S. subsidiary, Locke Insulators, Inc. (Locke), as the primary producer/exporter and importer of subject merchandise.[4] The petitioners believe that Locke acts as a purchaser and reseller of subject merchandise produced by NGK; therefore, the petitioners calculated a constructed export price (CEP). The starting price for CEP is a simple average of two price quotes for NGK merchandise during the POI. These price quotes, which are for a particular model of subject merchandise, are identified in affidavits filed by representatives of two of the petitioning companies (Lapp and Victor) and were obtained from a customer and sales agent.

The petitioners calculated net U.S. price by deducting from the starting price U.S. sales commissions, inventory carrying costs, U.S. warehousing expenses, U.S. imputed credit expenses, foreign inland freight, ocean freight, U.S. customs duty and fees, U.S. inland freight, U.S. indirect selling expenses, and an amount for CEP profit. See *Initiation Checklist*.

Normal Value

The starting price for normal value (NV) is a weighted-average of four home market price quotes that were obtained through foreign market research. These price quotes, which were made during the POI, are for subject merchandise of the same grade as that of the merchandise for which U.S. price quotes were obtained. The petitioners made circumstance of sale adjustments to NV for imputed credit expenses, as well as adjustments for packaging costs and inland freight expenses.

Based upon a comparison of CEP to NV, the petitioners calculated an estimated dumping margin of 105.8 percent.

[4] The petitioners also identified Daito Co., Ltd., and Koransha Co., Ltd. as Japanese producers of station post insulators but stated that they were not aware of any exports of such merchandise by these companies to the United States.

Fair Value Comparisons

Based on the data provided by the petitioners, there is reason to believe that imports of subject merchandise from Japan are being, or are likely to be, sold in the United States at less than fair value.

Allegations and Evidence of Material Injury and Causation

The petitioners allege that the U.S. industry producing the domestic like product is being materially injured, or is threatened with material injury, by reason of the imports of the subject merchandise sold at less than NV. The volume of imports from Japan, using the latest available data, exceeded the statutory threshold of three percent for a negligibility exclusion. *See* section 771(24)(A)(i) of the Act. The petitioners contend that the industry's injured condition is evidenced in the declining trends in operating profits, decreased U.S. market share, and price suppression and depression. The allegations of injury and causation are supported by relevant evidence including U.S. Customs import data, domestic consumption, and pricing information. We have assessed the allegations and supporting evidence regarding material injury and causation, and have determined that these allegations are properly supported by accurate and adequate evidence and meet the statutory requirements for initiation. See *Initiation Checklist*.

Initiation of Antidumping Investigation

Based on our examination of the petition on station post insulators from Japan, and the petitioners' response to our supplemental questionnaire clarifying the petition, we find that the petition meets the requirements of section 732 of the Act. See *Initiation Checklist*. Therefore, we are initiating an antidumping duty investigation to determine whether imports of station post insulators from Japan are being, or are likely to be, sold in the United States at less than fair value. Unless this deadline is extended, we will make our preliminary determination no later than 140 days after the date of this initiation.

Distribution of Copies of the Petition

In accordance with section 732(b)(3)(A) of the Act, a copy of the public version of the petition has been provided to the representatives of the government of Japan. We will attempt to provide a copy of the public version of the petition to each exporter named in the petition, as appropriate.

International Trade Commission Notification

We have notified the ITC of our initiation, as required by section 732(d) of the Act.

Preliminary Determination by the ITC

The ITC will determine, no later than February 14, 2003, whether there is a reasonable indication that imports of subject merchandise from Japan are causing material injury, or threatening to cause material injury, to a U.S. industry. A negative ITC determination will result in the investigation being terminated; otherwise, this investigation will proceed according to statutory and regulatory time limits.

This notice is issued and published pursuant to section 777(i) of the Act.

Dated: January 21, 2003.

Faryar Shirzad,

Assistant Secretary for Import Administration.

[FR Doc. 03–1899 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–DS–S

DEPARTMENT OF COMMERCE

International Trade Administration

[A-427–814]

Notice of Amended Final Results of Antidumping Duty Administrative Review: Stainless Steel Sheet and Strip in Coils from France

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

ACTION: Notice of Amended Final Results of Antidumping Duty Administrative Review of Stainless Steel Sheet and Strip in Coils from France.

EFFECTIVE DATE: January 28, 2003.

FOR FURTHER INFORMATION CONTACT: Alex Villanueva, AD/CVD Enforcement Group III, Office IX, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, N.W., Washington, D.C. 20230; telephone: (202) 482–3208.

SUPPLEMENTARY INFORMATION:

Scope of the Review

For purposes of this administrative review, the products covered are certain stainless steel sheet and strip in coils. Stainless steel is an alloy steel containing, by weight, 1.2 percent or less of carbon and 10.5 percent or more of chromium, with or without other elements. The subject sheet and strip is a flat-rolled product in coils that is

greater than 9.5 mm in width and less than 4.75 mm in thickness, and that is annealed or otherwise heat treated and pickled or otherwise descaled. The subject sheet and strip may also be further processed (*e.g.*, cold-rolled, polished, aluminized, coated, *etc.*) provided that it maintains the specific dimensions of sheet and strip following such processing.

The merchandise subject to this review is classified in the *Harmonized Tariff Schedule of the United States* (HTS) at subheadings: 7219.13.0031, 7219.13.0051, 7219.13.0071, 7219.1300.81[1], 7219.14.0030, 7219.14.0065, 7219.14.0090, 7219.32.0005, 7219.32.0020, 7219.32.0025, 7219.32.0035, 7219.32.0036, 7219.32.0038, 7219.32.0042, 7219.32.0044, 7219.33.0005, 7219.33.0020, 7219.33.0025, 7219.33.0035, 7219.33.0036, 7219.33.0038, 7219.33.0042, 7219.33.0044, 7219.34.0005, 7219.34.0020, 7219.34.0025, 7219.34.0030, 7219.34.0035, 7219.35.0005, 7219.35.0015, 7219.35.0030, 7219.35.0035, 7219.90.0010, 7219.90.0020, 7219.90.0025, 7219.90.0060, 7219.90.0080, 7220.12.1000, 7220.12.5000, 7220.20.1010, 7220.20.1015, 7220.20.1060, 7220.20.1080, 7220.20.6005, 7220.20.6010, 7220.20.6015, 7220.20.6060, 7220.20.6080, 7220.20.7005, 7220.20.7010, 7220.20.7015, 7220.20.7060, 7220.20.7080, 7220.20.8000, 7220.20.9030, 7220.20.9060, 7220.90.0010, 7220.90.0015, 7220.90.0060, and 7220.90.0080. Although the HTS subheadings are provided for convenience and Customs purposes, the Department's written description of the merchandise under review is dispositive.

Excluded from the scope of this review are the following: (1) sheet and strip that is not annealed or otherwise heat treated and pickled or otherwise descaled, (2) sheet and strip that is cut to length, (3) plate (*i.e.*, flat-rolled stainless steel products of a thickness of 4.75 mm or more), (4) flat wire (*i.e.*, cold-rolled sections, with a prepared edge, rectangular in shape, of a width of not more than 9.5 mm), and (5) razor blade steel. Razor blade steel is a flat-rolled product of stainless steel, not further worked than cold-rolled (cold-reduced), in coils, of a width of not more than 23 mm and a thickness of 0.266 mm or less, containing, by weight, 12.5 to 14.5 percent chromium, and certified at the time of entry to be used in the manufacture of razor blades. *See* Chapter 72 of the HTS, ''Additional U.S. Note'' 1(d).

In response to comments by interested parties, the Department has determined that certain specialty stainless steel products are also excluded from the scope of this review. These excluded products are described below.

Flapper valve steel is defined as stainless steel strip in coils containing, by weight, between 0.37 and 0.43 percent carbon, between 1.15 and 1.35 percent molybdenum, and between 0.20 and 0.80 percent manganese. This steel also contains, by weight, phosphorus of 0.025 percent or less, silicon of between 0.20 and 0.50 percent, and sulfur of 0.020 percent or less. The product is manufactured by means of vacuum arc remelting, with inclusion controls for sulphide of no more than 0.04 percent and for oxide of no more than 0.05 percent. Flapper valve steel has a tensile strength of between 210 and 300 ksi, yield strength of between 170 and 270 ksi, plus or minus 8 ksi, and a hardness (Hv) of between 460 and 590. Flapper valve steel is most commonly used to produce specialty flapper valves in compressors.

Also excluded is a product referred to as suspension foil, a specialty steel product used in the manufacture of suspension assemblies for computer disk drives. Suspension foil is described as 302/304 grade or 202 grade stainless steel of a thickness between 14 and 127 microns, with a thickness tolerance of plus-or-minus 2.01 microns, and surface glossiness of 200 to 700 percent Gs. Suspension foil must be supplied in coil widths of not more than 407 mm, and with a mass of 225 kg or less. Roll marks may only be visible on one side, with no scratches of measurable depth. The material must exhibit residual stresses of 2 mm maximum deflection, and flatness of 1.6 mm over 685 mm length.

Certain stainless steel foil for automotive catalytic converters is also excluded from the scope of this review. This stainless steel strip in coils is a specialty foil with a thickness of between 20 and 110 microns used to produce a metallic substrate with a honeycomb structure for use in automotive catalytic converters. The steel contains, by weight, carbon of no more than 0.030 percent, silicon of no more than 1.0 percent, manganese of no more than 1.0 percent, chromium of between 19 and 22 percent, aluminum of no less than 5.0 percent, phosphorus of no more than 0.045 percent, sulfur of no more than 0.03 percent, lanthanum of less than 0.002 or greater than 0.05 percent, and total rare earth elements of more than 0.06 percent, with the balance iron.

Permanent magnet iron-chromium-cobalt alloy stainless strip is also excluded from the scope of this review. This ductile stainless steel strip contains, by weight, 26 to 30 percent chromium, and 7 to 10 percent cobalt, with the remainder of iron, in widths 228.6 mm or less, and a thickness between 0.127 and 1.270 mm. It exhibits magnetic remanence between 9,000 and 12,000 gauss, and a coercivity of between 50 and 300 oersteds. This product is most commonly used in electronic sensors and is currently available under proprietary trade names such as ''Arnokrome III.''[2]

Certain electrical resistance alloy steel is also excluded from the scope of this review. This product is defined as a non-magnetic stainless steel manufactured to American Society of Testing and Materials (''ASTM'') specification B344 and containing, by weight, 36 percent nickel, 18 percent chromium, and 46 percent iron, and is most notable for its resistance to high temperature corrosion. It has a melting point of 1390 degrees Celsius and displays a creep rupture limit of 4 kilograms per square millimeter at 1000 degrees Celsius. This steel is most commonly used in the production of heating ribbons for circuit breakers and industrial furnaces, and in rheostats for railway locomotives. The product is currently available under proprietary trade names such as ''Gilphy 36.''[3]

Certain martensitic precipitation-hardenable stainless steel is also excluded from the scope of this review. This high-strength, ductile stainless steel product is designated under the Unified Numbering System (''UNS'') as S45500-grade steel, and contains, by weight, 11 to 13 percent chromium, and 7 to 10 percent nickel. Carbon, manganese, silicon and molybdenum each comprise, by weight, 0.05 percent or less, with phosphorus and sulfur each comprising, by weight, 0.03 percent or less. This steel has copper, niobium, and titanium added to achieve aging, and will exhibit yield strengths as high as 1700 Mpa and ultimate tensile strengths as high as 1750 Mpa after aging, with elongation percentages of 3 percent or less in 50 mm. It is generally provided in thicknesses between 0.635 and 0.787 mm, and in widths of 25.4 mm. This product is most commonly

[1] Due to changes to the HTS numbers in 2001, 7219.13.0030, 7219.13.0050, 7219.13.0070, and 7219.13.0080 are now 7219.13.0031, 7219.13.0051, 7219.13.0071, and 7219.13.0081, respectively.

[2] ''Arnokrome III'' is a trademark of the Arnold Engineering Company.

[3] ''Gilphy 36'' is a trademark of Imphy, S.A.

used in the manufacture of television tubes and is currently available under proprietary trade names such as ''Durphynox 17.''[4]

Finally, three specialty stainless steels typically used in certain industrial blades and surgical and medical instruments are also excluded from the scope of this review. These include stainless steel strip in coils used in the production of textile cutting tools (*e.g.*, carpet knives).[5] This steel is similar to AISI grade 420 but containing, by weight, 0.5 to 0.7 percent of molybdenum. The steel also contains, by weight, carbon of between 1.0 and 1.1 percent, sulfur of 0.020 percent or less, and includes between 0.20 and 0.30 percent copper and between 0.20 and 0.50 percent cobalt. This steel is sold under proprietary names such as ''GIN4 Mo.'' The second excluded stainless steel strip in coils is similar to AISI 420-J2 and contains, by weight, carbon of between 0.62 and 0.70 percent, silicon of between 0.20 and 0.50 percent, manganese of between 0.45 and 0.80 percent, phosphorus of no more than 0.025 percent and sulfur of no more than 0.020 percent. This steel has a carbide density on average of 100 carbide particles per 100 square microns. An example of this product is ''GIN5'' steel. The third specialty steel has a chemical composition similar to AISI 420 F, with carbon of between 0.37 and 0.43 percent, molybdenum of between 1.15 and 1.35 percent, but lower manganese of between 0.20 and 0.80 percent, phosphorus of no more than 0.025 percent, silicon of between 0.20 and 0.50 percent, and sulfur of no more than 0.020 percent. This product is supplied with a hardness of more than Hv 500 guaranteed after customer processing, and is supplied as, for example, ''GIN6''.[6]

Amendment of Final Results

On December 26, 2002, the Department of Commerce (''the Department'') published its final results for stainless steel sheet and strip in coils from France for the July 1, 2000, through June 30, 2001, period of review. *See Notice of Final Results of Antidumping Duty Administrative Review: Stainless Steel Sheet and Strip in Coils From France: Stainless Steel Sheet and Strip From France* (''*Final Results*''), 67 FR 78773 (December 26, 2002).

In accordance with 19 C.F.R. §351.224(c), on December 19, 2002, Ugine, S.A. (''Ugine''), a respondent in this administrative review, requested that the Department extend the deadline to file ministerial errors regarding the *Final Results* from December 24, 2002 to January 10, 2002. On December 20, 2002, the Department extended the deadline to file any ministerial allegations on the *Final Results* from December 24, 2002 to December 31, 2002. *See* Letter from the Department to Ugine, dated December 20, 2002. Consequently, on December 31, 2002, Ugine and the Petitioners[7] timely filed an allegation that the Department made ministerial errors in the *Final Results*, pursuant to 19 C.F.R. §351.224(c). Ugine submitted rebuttal comments on January 6, 2003 in reply to the Petitioners' ministerial error allegations.

Arm's Length Test Program

The Petitioners contend that in its *Final Results*, the Department, in calculating the net price, inadvertently failed to consider both home market interest revenue (INTREVH) and home market commissions (COMMH). Thus, according to the Petitioners, the Department should revise its *Final Results* to add home market interest revenue and deduct home market commissions in calculating the net price in the arm's length test, consistent with its standard practice.

Model Match Program

The Petitioners note that the Department's model match program used for the *Final Results*, contained two errors. According to the Petitioners, in the model match program, the Department erred in calculating the home market net price because it did not add home market interest revenue (INTREVH) in the calculation. Therefore, the Petitioners assert, the Department should revise its home market net price calculation to add home market interest revenue in the model match program in accordance with its standard practice.

The Petitioners also argue that in its *Final Results*, the Department inadvertently failed to update the date of payment for unpaid sales (where PAYDTU/H equals '' ''). According to the Petitioners, the Department's standard policy in final administrative results is to update the date of payment for unpaid sales to the last day of each market's respective verifications and to recalculate credit expenses (CREDITU/H), as appropriate. *See Notice of Final Determination of Sales at Less Than Fair Value: Structural Steal Beams from Italy and accompanying Issues and Decision Memorandum*, dated May 20, 2002, at Comment 9. Therefore, the Petitioners argue that for home market sales this date of payment was June 21, 2002, and for U.S. market sales it was May 24, 2002. *See Memorandum to the File from Alex Villanueva, Import Compliance Specialist, through James C. Doyle, Program Manager, Verification Report of the 2nd Administrative Review of Stainless Steel Sheet and Strip in Coils from France Home Market Sales and Cost Verification Report of Ugine, S.A.* (''*Home Market Verification Report*''), dated July 31, 2002, at 1, and *Memorandum to the File from Alex Villanueva and Jonathan Herzog, Import Compliance Specialists, through James C. Doyle, Program Manager, Verification Report of the 2nd Administrative Review of Stainless Steel Sheet and Strip in Coils from France U.S. Sales and Cost Verification Report of Ugine, S.A.* (''*U.S. Market Verification Report*''), dated July 31, 2002 at 1. Thus, the Petitioners argue, the Department should revise its *Final Results* to update the date of payment for unpaid home market and U.S. market sales to the last day of verification in the model match program.

Margin Calculation Program

The Petitioners argue that in calculating the values that would be used to determine the Constructed Export Price (''CEP'') profit in the *Final Results*, the Department inadvertently mixed U.S. dollar-based variables with Euro-based variables without performing the proper conversion. The Petitioners note that this occurred when the Department calculated the cost of goods sold for U.S. sales when the Department combined the U.S. dollar-based further manufacturing, general and administrative expenses, interest expenses and packing expenses. Furthermore, the Petitioners note, the mixed-currency costs of good sold for U.S. sales was then added to the Euro-based home market costs of goods sold. Similarly, the Petitioners claim, the U.S. dollar-based revenue for U.S. sales was added to Euro-based revenue for home market sales. Finally, the Petitioners argue that the same error was performed with regard to selling expenses and movement expenses. The Petitioners argue that in order to correct for this error, the Department should convert all U.S. dollar-denominated variables (FURMANU, REVENU, SELLEXPU,

[4] ''Durphynox 17'' is a trademark of Imphy, S.A.

[5] This list of uses is illustrative and provided for descriptive purposes only.

[6] ''GIN4 Mo,'' ''GIN5'' and ''GIN6'' are the proprietary grades of Hitachi Metals America, Ltd.

[7] The Petitioners in this case are Allegheny Ludlum Corporation, AK Steel, Inc., North American Stainless, United Steelworkers of America, AFL-CIO/CLC, Butler Armco Independent Union and Zanesville Armco Independent Organization.

MOVEXPU) to Euros in the margin calculation program.

In addition, the Petitioners argue that the Department failed to update the day of payment for unpaid sales (where PAYDTU/H equals ‘‘ ’’) in the margin calculation program. According to the Petitioners, the Department's normal practice is to update the date of payment for unpaid sales to the last date of each verification and to recalculate credit expenses (CREDITU/H) appropriately. As noted above, the Petitioners argue, the last date of verification for home market sales was June 21, 2002, and for U.S. market sales was May 24, 2002. Thus, the Petitioners request that the Department revise its Final Results to update the date of payment for unpaid home market and U.S. market sales to the last day of verification for each respective market in the margin calculation program.

Ugine argues that in the *Final Results*, the Department attempted to take interest revenue into account when calculating the net U.S. price in the margin calculation program, but inserted the programming code incorrectly before the ‘‘End’’ statement. Therefore, to correct this error, Ugine requests that the Department revise its programming code to properly take into account the interest revenue when calculating the net U.S. price in the margin calculation program.

In their rebuttal comments, Ugine argues that the Petitioners' claim that the Department ‘‘inadvertently’’ used the same method for calculating credit expenses in both the preliminary and final results. According to Ugine, the Petitioners suggest that the Department intended to ‘‘update’’ the methodology by inserting an assumed payment date for sales for which payment had not been received and recalculating the reported credit expenses based on this assumed payment date in both the model match and the margin programs. Ugine notes, that the Department, however, gave no indication in its preliminary results or *Final Results* that it was contemplating the methodological change the Petitioners are now suggesting. Furthermore, Ugine argues, nor did the Petitioners raise this issue in their case brief or rebuttal brief. Consequently, Ugine notes, it is now too late for the Petitioners to advance this methodological change to the calculation after the Department has completed its *Final Results*.

In addition, Ugine argues that under the credit expense methodology used by the Department in its preliminary and *Final Results*, there is no basis for the Petitioners' suggested ‘‘update’’ to the calculations. According to Ugine, in the Department's preliminary results, credit expenses for those sales for which payment had not been received were calculated using an estimated credit period. Ugine asserts that the estimated credit period for these sales was based on the weighted-average credit period for sales during the reporting period for which payment dates were available. Ugine argues that the Petitioners' comments have not shown this methodology to be inaccurate or erroneous, and therefore, provide no basis for the Department to jettison this calculation methodology, even if these arguments were timely.

Finally, Ugine notes, that for U.S. sales made by Hague, the Petitioners' suggested ‘‘update’’ is simply inapplicable. According to Ugine, the credit period for all sales by Hague was determined based on an accounts-receivable turnover analysis because Hague was not able to identify the payment date for individual transactions. Therefore, Ugine argues, the fact that no payment date was reported for these sales does not mean that payment had not been received, but that is simply a function of the reporting methodology used by Hague. Ugine states that this methodology was verified by the Department without discrepancy and has been accepted by the Department in all prior reviews of this case. Accordingly, Ugine claims, even if the Department were to accept the Petitioners' comment, the credit expenses calculated for Hague's sales should not be affected.

Department's Position

We agree with Ugine and the Petitioners.

With regard to the Petitioners' argument regarding the treatment of interest revenue and commissions paid for home market sales in the arm's length test, we agree. In our *Final Results*, we inadvertently failed to consider both home market interest revenue (INTREVH) and home market commissions (COMMH) in calculating the net price. Thus, to correct for this error, we have revised our *Final Results* and added home market interest revenue and deducted home market commissions in calculating the net price in the arm's length test.

With regard to the Petitioners' argument that the Department erred in calculating the home market net price because we did not add home market interest revenue (INTREVH) to the calculation in the model match program, we agree. Therefore, for these amended final results, we correctly revised our home market net price calculation and added home market interest revenue in the model match program.

With regard to the Petitioners' argument that in calculating the values that would be used to determine the CEP profit in the *Final Results*, we mistakenly mixed U.S. dollar-based variables with Euro-based variables without performing the proper conversion in the margin calculation program, we agree. To correct for this error, we properly converted all U.S. dollar-denominated variables (FURMANU, REVENU, SELLEXPU, MOVEXPU) to Euros in the margin calculation program.

With regard to Ugine's argument that Department incorrectly applied the programming code to account for interest revenue when calculating the net U.S. price, we agree. We note that although the programming code is correct, it was inadvertently placed in the incorrect order, preventing the program from taking interest revenue into account when calculating the net U.S. price. For these amended final results, we have correctly applied the programming code to take interest revenue into account when calculating the net U.S. price in the margin calculation program.

With regard to the Petitioners' argument that we failed to update the date of payment for unpaid sales (where PAYDTU/H equals ‘‘ ’’) in the margin and model match calculation programs, we disagree. It is the Department's standard practice to replace the date of payment with the last day of verification of that particular market (*i.e.*, the last day of the home market verification should be used as the date of payment for unpaid home market sales and the last day of the U.S. market verification should be used as the date of payment for unpaid U.S. market sales). However, in the instant case, the home market sales have a date of payment. Ugine reported, as it has reported in the investigation and the first administrative review, an average payment date for its home market sales where payment had not yet been received. Additionally, credit expenses for those sales for which payment had not been received were calculated using a weighted-average credit period. Therefore, the Petitioners assertion that certain home market sales had no payment date is wrong. In addition, in our *Final Results* we did not intend to replace Ugine's average payment date methodology with the last day of the home market sales verification. Consequently, we are affirming our use of Ugine's average payment date for sales for which payment had not been

received in the home market and are not changing our *Final Results*.

With regard to the Petitioners similar argument regarding sales where there was no date of payment (PAYDTU) in the U.S. market, we disagree. We agree with Ugine that the date of payment reported was based on an accounts-receivable turnover methodology because Hague was not able to identify the date of payment on a sales-specific basis. Furthermore, the credit period for sales made by Hague was determined based on this same methodology. At the U.S. market verification, we verified this methodology and found no discrepancies. *See U.S. Market Verification Report* at 18. This fact was not disputed by the Petitioners. Therefore, for the *Final Results*, we have not changed the date of payment used by Hague.

Therefore, we are amending the *Final Results* to reflect the correction of the above-cited ministerial errors. All changes made to the arm's length test, model match and margin program can be found in the analysis memorandum. *See Memorandum to the File from Alex Villanueva, Senior Case Analyst to James C. Doyle, Program Manager, Final Analysis for Ugine S.A. for the Amended Final Results of the 2nd Administrative Review Stainless Steel Sheet and Strip in Coils from France for the period July 1, 2000 through June 30, 2001*, dated January 20, 2003.

The weighted-average dumping margin is as follows:

Producer/Manufacturer Exporter	Final Weighted-Average Margin (percent)	Amended Final Weighted Average Margin (percent)
Ugine, S.A.	1.47	1.44

Consequently, we are issuing and publishing these amended final results and notice in accordance with sections 751(a)(1) of the Act.

Dated: January 17, 2002.

Faryar Shirzad,

Assistant Secretary for Import Administration.

[FR Doc. 03–1902 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–DS–S

DEPARTMENT OF COMMERCE

International Trade Administration

[C-122–815]

Alloy Magnesium from Canada: Preliminary Results of Countervailing Duty New Shipper Review

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

ACTION: Notice of Preliminary Results of Countervailing Duty New Shipper Review.

SUMMARY: In response to a request from Magnola Metallurgy, Inc., the Department of Commerce is conducting a new shipper review of the countervailing duty order on alloy magnesium from Canada for the period January 1, 2001 through December 31, 2001. In these preliminary results, we find that Magnola Metallurgy, Inc. received countervailable subsidies during the period of review. *The ad valorem* rate is shown in the ''Preliminary Results of Review'' section of this notice. If these preliminary results are adopted in our final results, we will instruct the Customs Service to assess countervailing duties.

Interested parties are invited to comment on these preliminary results (see the Public Comment section of this notice).

EFFECTIVE DATE: January 28, 2003.

FOR FURTHER INFORMATION CONTACT: Melanie Brown, Office 1, Group 1, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington DC 20230; telephone (202) 482–4987.

SUPPLEMENTARY INFORMATION:

Background

On August 31, 1992, the Department of Commerce (''Department'') published in the **Federal Register** the countervailing duty orders on pure magnesium and alloy magnesium from Canada. *See Final Affirmative Countervailing Duty Determinations: Pure Magnesium and Alloy Magnesium from Canada*, 57 FR 39392 (July 13, 1992) (''*Investigation Final*''). On February 28, 2002, the Department received a timely request for a new shipper review from Magnola Metallurgy, Inc. (''Magnola'') pursuant to 19 CFR 351.214(d). On March 27, 2002, the Department initiated the new shipper review for the period January 1, 2001 through December 31, 2001. *See Pure and Alloy Magnesium From Canada: Notice of Initiation of New Shipper Countervailing Review*, 67 FR 15794 (April 3, 2002). On May 8, 2002, U.S. Magnesium,[1] (''the petitioner'') submitted allegations of countervailable subsidies received by Magnola. Magnola commented on these allegations on May 15, 2002.

On July 10, 2002, the Department issued its initial countervailing questionnaires to Magnola, the Government of Québec (''GOQ''), and the Government of Canada (''GOC''). We received questionnaire responses form the GOQ and the GOC on August 15, 2002, and from Magnola on August 16, 2002. Subsequent to the receipt of the initial questionnaire responses, we issued supplemental questionnaires, received comments from the petitioners, and received supplemental questionnaire responses from the GOQ, the GOC, and Magnola.

On September 13, 2002, the Department found that because of the complexity of the issues involved in this case it was not practicable to complete the review in the time allotted. Therefore, we published an extension of the time limit for the completion of the preliminary results of this review to no later than January 21, 2003, in accordance with section 751(a)(2)(B) of the Act and 19 CFR 351.214(h)(2). We also rescinded the review with respect to pure magnesium because Magnola's request for the new shipper review was for Magnola's sales of alloy magnesium from Canada only. *See Alloy Magnesium from Canada: Extension of Time Limit for the Preliminary Results of the Countervailing Duty New Shipper Review and Pure Magnesium from Canada; Rescission of Countervailing Duty New Shipper Review*, 67 FR 50819 (September 13, 2002).

New Subsidy Allegation

On August 9, 2002, the petitioner submitted a new subsidy allegation and documentation supporting the allegation. On August 19 and September 3, 2002, Magnola submitted comments objecting to the consideration of new subsidies. We considered the information on the record and initiated an investigation on one additional program allegedly operated by the GOQ: Emploi-Québec Manpower Training Mandate (''MTM''). For more information, see the memorandum to Richard Moreland, Deputy Assistant Secretary entitled, ''New Subsidy

[1] The original petition was filed by Magnesium Corporation of America, (''Magcorp''). On July 31, 2002, the petitioner informed the Department that Magcorp had been sold to U.S Magnesium.

Allegation - Canadian Magnesium New Shipper Review,'' dated September 6, 2002, which is on file in the Commerce Department's Central Records Unit in Room B-099 of the main Commerce Department Building (''CRU'').

Scope of the Review

The products covered by this review are shipments of alloy magnesium from Canada. Magnesium alloys contain less than 99.8 percent magnesium by weight with magnesium being the largest metallic element in the alloy by weight, and are sold in various ingot and billet forms and sizes. The alloy magnesium subject to review is currently classifiable under item 8104.19.0000 of the *Harmonized Tariff Schedule of the United States* (''HTSUS''). Although the HTSUS subheading is provided for convenience and customs purposes, the written description of the merchandise subject to the order is dispositive.

Secondary and granular magnesium are not included in the scope of this order. Our reasons for excluding granular magnesium are summarized in *Preliminary Determination of Sales at Less Than Fair Value: Pure and Alloy Magnesium From Canada*, 57 FR 6094 (February 20, 1992).

Subsidies Valuation Information

Allocation Period

Pursuant to 19 CFR 351.524(b), non-recurring subsidies are allocated over a period corresponding to the average useful life (''AUL'') of the renewable physical assets used to produce the subject merchandise. Section 351.524(d)(2) of the regulations creates a rebuttable presumption that the AUL will be taken from the U.S. Internal Revenue Service's 1977 Class Life Asset Depreciation Range System (''the IRS Tables''). For magnesium, the IRS Tables prescribe an AUL of 14 years.

In order to rebut the presumption in favor of the IRS Tables, the challenging party must show that the IRS Tables do not reasonably reflect the company-specific AUL or the country-wide AUL for the industry in question, and that the difference between the company-specific or country-wide AUL and the IRS tables is significant. (*See* 19 CFR 351.524(d)(2)(i).) For this difference tobe considered significant, it must be one year or greater. (*See* 19 CFR 351.524(d)(2)(ii).)

Late in these proceedings, Magnola claimed a 28-year company-specific AUL. The company was unable to provide historical or actual depreciation costs because it was still in its start-up phase and not yet operating at commercial levels. Instead, Magnola provided an AUL calculation based on a prediction of future depreciation expenses and asset values (based on pre-production costs) over a 40-year horizon. Therefore, we preliminarily find that Magnola has not satisfied the requirements of section 351.524(d)(2)(iii) of our regulations and has not demonstrated that its proposed company-specific AUL reflects actual depreciation expenses and asset values for magnesium. We therefore have allocated Magnola's non-recurring benefits over 14 years as prescribed in the IRS Tables.

For non-recurring subsidies, we applied the ''0.5 percent expense test'' described in section 351.524(b)(2) of our regulations. In this test, we compare the amount of subsidies approved under a given program in a particular year to sales (total or export, as appropriate) in that year. If the amount of subsidies is less that 0.5 percent of sales, the benefits are expensed in their entirety in the year of receipt rather than allocated over the AUL period.

Discount Rates

In accordance with section 351.524(d)(3) of the regulations, it is the Department's preference to use a company's long-term fixed-rate cost of borrowing in the same year a grant was approved as the discount rate. However, where a company does not have a loan that could be used as a discount rate, the Department's next preference is to use the average cost of long-term fixed-rate loans in the country in question.

Magnola did not have long-term, fixed-rate, Canadian dollar loans or other debt obligations during 1998 or 2000, the years in which the MTM grants were approved. Therefore, we used the Canadian average rate of return on long-term commercial bonds as discount rates for the years 1998 and 2000.

Analysis of Programs

I. Program Preliminarily Found to Confer Countervailable

• Subsidies Emploi-Québec Manpower Training Mandate (''MTM'')

Emploi-Québec (''E-Q'') is a labor-focused government unit created under the laws of Québec that administers the manpower and employment policies on behalf of Québec's Ministry of Employment and Solidarity (*Ministère de L'Emploi et de la Solidarité sociale*). The goal of the E-Q is to improve and develop the labor market in the region of Québec. To accomplish this goal, in 1998 the MTM program was established to provide financial support, in the form of grants, to companies with approved training programs. Up to 50 percent of a company's training expenses, normally over a period of 24-months, are reimbursed under the MTM program with funding from the Labor Market Development Fund (*Fonds de développement du marché du travail*) (''LMDF''), a central fund established by the Government of Québec to finance the labor objectives of the E-Q. With the exception of government-affiliated agencies, companies in all industries are eligible for these benefits.

Under the MTM program, there are two funding levels under which companies may receive reimbursement of labor training expenses: small-scale economic projects and major economic projects. Projects at both funding levels must satisfy the E-Q's five policy objectives of job preparation, job integration, job management, job stabilization, and job creation, before becoming eligible for reimbursement. Once the five objectives are met, companies are eligible to receive reimbursement of 50 percent of their labor training expenses. Small-scale project recipients are eligible to receive a maximum reimbursement of $100,000.

The $100,000 reimbursement limit does not apply to major economic projects. However, major economic projects are required to: 1) create either 50 jobs or 100 jobs in 24 months, depending on whether the company is a new company or a company that has been in operation; 2) have the approval of the Ministry's *Commission des partenaires du marche du travail* (''CPMT''); and 3) agree to close monitoring by the E-Q. The LMDF sets aside $40 million annually to finance major economic projects and while all industries are eligible to receive funding, priority is given to manufacturing sectors where exporting is a priority and to projects from the service, commerce and accommodation sectors, if they have the potential to attract an international clientele or foreign business to Québec.

In 1998, Magnola submitted a human resource development plan to the E-Q that described its new magnesium plant, the new technology it would be using and the training programs that Magnola needed to develop a sufficiently skilled workforce. Magnola met the criteria for eligibility as a major economic project. In 1998 and 2000, the E-Q approved grants to reimburse 50 percent of Magnola's training expenses.

Because there are two funding levels in the MTM program, we are conducting an analysis to determine if the two levels are integrally linked and should be treated as one program. According to § 351.502(c) of the Department's

regulations, the Secretary may find two or more programs integrally linked if: 1) the subsidy programs have the same purpose, 2) the subsidy programs bestow the same type of benefit, 3) the subsidy programs confer similar levels of benefits on similarly situated firms, and 4) the subsidy programs were linked at inception.

In the instant review we find that both the small-scale economic projects and the major economic projects were established under the MTM program to improve the labor conditions in Québec and hence, have the same purpose. Second, the benefit bestowed at both funding levels is the same because at both funding levels recipients are reimbursed for 50 percent of training expenses in the form of grants. Moreover, at both funding levels, the projects confer similar levels of benefits on similarly situated firms because firms with similar levels of training expenses are treated equally. Finally, with respect to the fourth criteria, the two funding levels were linked at the inception of the MTM program. Based on the above, we find that the two funding levels of the MTM program meet the integral linkage requirements. Consequently, for purposes of this review, we find that the MTM program for small-scale economic projects and major economic projects are integrally linked and consider them to be a single program.

We find that the MTM grants Magnola received in 1998 and 2000 constitute countervailable subsidies within the meaning of section 771(5) of the Act. We find a financial contribution under section 771(5)(D)(i) because the grants are a direct transfer of funds from the GOQ that confer a financial benefit to Magnola in the amount of the grants. In order to determine whether the MTM program is *de facto* specific, we conducted a ''disproportionate benefit'' analysis on an industry-specific and on a company-specific basis according to section 771(5A)(D)(iii)(III) of the Act. We reviewed the information available on the industry of recipients in the MTM program and compared the benefit amount received by the metals industry to the amounts received by all other recipient industries. We found that from 1998 through 2001, the metals industry received a disproportionately large amount of MTM benefits compared to other industries.

We then conducted a company-specific analysis by comparing the benefits received by Magnola to those received by other major economic project recipients, the only recipients for which we had company-specific data. We found that from 1998 through 2001, Magnola received a disproportionately large amount of benefits compared to other major economic project recipients. While the company-specific analysis was based on major economic project recipients only, we note that based on the amount of funding received by small-scale project recipients, the inclusion of small scale projects would not have had a significant impact on our analysis. Taken together, these facts support a finding under section 771(5A)(D)(iii)(III) of the Act, that the MTM program assistance received by Magnola was disproportionate on an industry-specific and company-specific basis.

Concerning whether this program is an export subsidy, section 771(5A) of the Act states that an export subsidy ''is a subsidy that is, in law or in fact, contingent upon export performance, alone or as one of two or more conditions.'' In this review, the petitioner alleged the MTM program is export specific, citing to language in the MTM regulations that state that funding for projects ''from the manufacturing sector, where production is mainly destined to export is given priority....''

We reviewed this information with respect to section 771(5A)(B) of the Act and found that the MTM regulations do not meet the requirements of an export subsidy because MTM assistance was not contingent upon exportation. In this instance, we find that the term ''export'' used in the MTM regulations refers to exports outside the province of Québec and not to exports outside Canada. Moreover, there is no evidence on the record to support the finding that eligibility for MTM assistance was contingent upon exportation, whether provincially or outside Canada. The fact that a subsidy is awarded to a company that exports does not, by itself, make the subsidy an export subsidy within the meaning of the Act. *See Preliminary Negative Countervailing Duty Determination: Certain Laminated Hardwood Trailer Flooring from Canada*, 61 FR 59079 (November 20, 1996). Therefore, we preliminarily find that the MTM program is neither *de facto* nor *de jure*export specific.

In accordance with 19 CFR 351.524(c)(1) and (2), we have treated these grants as non-recurring subsidies because separate, project specific government approval was required to receive benefits, and funding for all projects under the MTM program was generally limited to 24 months. To calculate the benefit, we performed the expense test, as explained in the AUL section above, and found that the benefits approved in each year were more than 0.5 percent of Magnola's total sales. Therefore, we allocated the benefits over time. We used the grant methodology described in section 351.524(d) of the regulations to calculate the amount of benefit allocable to the POR. We then divided the benefit in the POR by Magnola's sales in the POR.

On this basis, we preliminarily find the net subsidy rate from the MTM program to be 7.00 percent *ad valorem* for Magnola.

II. Programs under which no benefit was received during the POR

• Federal Funding for a Feasibility Study under the Canada-Quebec Subsidiary Agreement on Industrial Development

The Department examined this program in the original investigations of pure and alloy magnesium and found that the GOC-provided assistance conferred a countervailable benefit. (*See Investigation Final*). Magnola received repayable contributions in 1996 and 1997, which were repaid to the GOC in 1998, with interest. Therefore, since Magnola repaid the benefits received prior to the POR, and no new funds were received during the POR, we find there is no benefit from this program during the POR.

III. Programs Preliminarily Found To Be Not Used

We examined the following programs and preliminarily find that Magnola did not apply for or receive benefits under these programs during the POR:

• St. Lawrence River Environment Technology Development Program
• Program for Export Market Development
• The Export Development Corporation
• Canada-Québec Subsidiary Agreement on the Economic Development of the Regions of Québec
• Opportunities to Stimulate Technology Programs
• Development Assistance Program
• Industrial Feasibility Study Assistance Program
• Export Promotion Assistance Program
• Creation of Scientific Jobs in Industries
• Business Investment Assistance Program
• Business Financing Program
• Research and Innovation Activities Program
• Export Assistance Program
• Energy Technologies Development Program
• Financial Assistance Program for Research Formation and for the Improvement of the Recycling Industry
• Transportation Research and Development Assistance Program

Preliminary Results of Review

In accordance with 19 CFR 351.221(b)(4)(i), we calculated a subsidy rate for Magnola, the sole producer/exporter subject to this new shipper review. For the period January 1, 2001, through December 31, 2001, we preliminarily find the net subsidy rate for Magnola to be 7.00 percent *ad valorem*. We will disclose our calculations to the interested parties pursuant to section 351.224(b) of the regulations.

Upon completion of this new shipper review, the Department will determine, and the Customs Service shall assess, countervailing duties on all appropriate entries. In accordance with 19 CFR 351.212(b)(2), we have calculated a company-specific assessment rate for merchandise subject to this review. The Department will issue appropriate assessment instructions directly to the Customs Service within 15 days of publication of the final results of review. If these preliminary results are adopted in the final results of review, we will direct the Customs Service to assess the resulting assessment rates against the entered customs values for the subject merchandise on each of the company's entries during the review period. The Department also intends to instruct Customs to collect cash deposits of estimated countervailing duties at the rate of 7.00 percent on the f.o.b. value of all shipments of the subject merchandise from Magnola entered, or withdrawn from warehouse, for consumption on or after the date of publication of the final results of this new shipper review.

Public Comment

Interested parties may request a hearing within 30 days of the date of publication of this notice. Any hearing, if requested, will be held two days after the scheduled date for submission of rebuttal briefs (*see* below). Interested parties may submit written arguments in case briefs within 30 days of the date of publication of this notice. Rebuttal briefs, limited to issues raised in case briefs, may be filed no later than five days after the date of filing the case briefs. Parties who submit briefs in these proceedings should provide a summary of the arguments not to exceed five pages and a table of statutes, regulations, and cases cited. Copies of case briefs and rebuttal briefs must be served on interested parties in accordance with 19 CFR 351.303(f).

Representatives of parties to the proceeding may request disclosure of proprietary information under administrative protective order no later than 10 days after the representative's client or employer becomes a party to the proceeding, but in no event later than the date the case briefs, under 19 CFR 351.309(c)(1)(ii), are due.

The Department will publish a notice of the final results of this new shipper review within 90 days of the publication of these preliminary results.

This new shipper review and notice is in accordance with sections 751(a)(2)(B)(iv)and 777(i) of the Act.

Dated: January 21, 2003.

Faryar Shirzad,

Assistant Secretary for Import Administration.

[FR Doc. 03–1898 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–DS–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[I.D. 011503A]

Marine Mammals and Endangered Species; File No 369–1440–01 and 1409

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Receipt of application for amendment and receipt of application for permit.

SUMMARY: Notice is hereby given that:

Dr. Bruce R. Mate, Oregon State University, has requested an amendment to scientific research Permit No. 369–1440–01; and

Karen G. Holloway-Adkins, Executive Director of East Coast Biologists, Inc., Indialantic, FL 32903, has applied for a scientific research permit.

DATES: Written or telefaxed comments must be received on or before February 27, 2003.

ADDRESSES: The amendment request, application and related documents are available for review upon written request or by appointment in the following office(s):

Permits, Conservation and Education Division, Office of Protected Resources, NMFS, 1315 East-West Highway, Room 13705, Silver Spring, MD 20910; phone (301)713–2289; fax (301)713–0376;

(Permit 369–1440) - Assistant Regional Administrator for Protected Resources, Northeast Region, NMFS, One Blackburn Drive, Gloucester, MA 01930–2298; phone (978)281–9346; fax (978)281–9371; and

(Permit 369–1440 and File No. 1409) - Assistant Regional Administrator for Protected Resources, Southeast Region, NMFS, 9721 Executive Center Drive North, St. Petersburg, FL 33702–2432; phone (727)570–5312; fax (727)570–5517.

Written comments or requests for a public hearing on this request should be submitted to the Chief, Permits, Conservation and Education Division, F/PR1, Office of Protected Resources, NMFS, 1315 East-West Highway, Room 13705, Silver Spring, MD 20910. Those individuals requesting a hearing should set forth the specific reasons why a hearing on this particular amendment request would be appropriate.

Comments may also be submitted by facsimile at (301)713–0376, provided the facsimile is confirmed by hard copy submitted by mail and postmarked no later than the closing date of the comment period. Please note that comments will not be accepted by e-mail or other electronic media.

FOR FURTHER INFORMATION CONTACT: Ruth Johnson, Carrie Hubard or Amy Sloan (301)713–2289.

SUPPLEMENTARY INFORMATION: The subject amendment to Permit No. 369–1440–01, issued on September 18, 1998 (63 FR 52686) is requested under the authority of the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), the Regulations Governing the Taking and Importing of Marine Mammals (50 CFR part 216), the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*) and the regulations governing the taking, importing, and exporting of endangered and threatened species (50 CFR 222–226).

Permit No. 369–1440–01 (Dr. Mate) authorizes the permit holder to: (1) approach to tag/biopsy sample, photograph and evaluate tag attachment on seven species of large whales; (2) opportunistically photograph an unlimited number of cetaceans and pinnipeds; (3) conduct research in the North Pacific, North Atlantic and International waters thereof; and (4) import/export samples for genetic analysis. The permit holder now requests authorization to conduct tagging/biopsy sampling on up to 24 fin whales (*Baleanoptera physalus*) in the Mediterranean Sea.

Ms. Holloway-Adkins (File No. 1409) requests a permit to take 100 green sea turtles (*Chelonia mydas*) and 10 loggerhead sea turtles (*Caretta caretta*) annually for scientific research. Turtles will be captured, handled, measured, weighed, flipper and PIT tagged, and lavaged. The research will characterize the turtle aggregations using the nearshore reefs in central Brevard County as developmental habitat, their

size class and foraging habitats and movements.

In compliance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), an initial determination has been made that the activity proposed is categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement.

Concurrent with the publication of this notice in the **Federal Register**, NMFS is forwarding copies of the amendment request to the Marine Mammal Commission and its Committee of Scientific Advisors.

Dated:January 21, 2003.

Stephen L. Leathery,

Chief, Permits, Conservation and Education Division, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 03–1907 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Telecommunications and Information Administration

Docket No. 010222048–3014–08

The Utility Service Cancellation Notices Exception to the Electronic Signatures in Global and National Commerce Act

AGENCY: National Telecommunications and Information Administration (NTIA), U.S. Department of Commerce

ACTION: Notice, Request For Comments

SUMMARY: Section 101 of the Electronic Signatures in Global and National Commerce Act, Pub. L. No. 106–229, *codified at* 15 U.S.C. 7001 *et seq.* (''ESIGN'' or ''the Act''), preserves the legal effect, validity, and enforceability of signatures and contracts relating to electronic transactions and electronic signatures used in the formation of electronic contracts. 15 U.S.C. 7001(a). Section 103 (a) and (b) of the Act, however, provides that the provisions of section 101 do not apply to contracts and records governed by statutes and regulations regarding court documents; probate and domestic law matters; state commercial law; consumer law covering utility services, residential property foreclosures and defaults, and insurance benefits; product recall notices; and hazardous materials documents. Section 103 of the Act also requires the Secretary of Commerce, through the Assistant Secretary for Communications, to review the operation of these exceptions to evaluate whether they continue to be necessary for consumer protection, and to make recommendations to Congress based on this evaluation. 15 U.S.C. 7003(c)(1). This Notice is intended to solicit comments from interested parties for purposes of this evaluation, specifically on the utility cancellation notices exception to the ESIGN Act. *See* 15 U.S.C. 7003(a)(3). NTIA has published separate notices requesting comment on the other exceptions listed in section 103 of the ESIGN Act.[1]

DATES: Written comments and papers are requested to be submitted on or before March 31, 2003.

ADDRESSES: Written comments should be submitted to Josephine Scarlett, National Telecommunications and Information Administration, 14th Street and Constitution Ave., N.W., Washington, DC 20230. Paper submissions should include a three and one-half inch computer diskette in HTML, ASCII, Word, or WordPerfect format (please specify version). Diskettes should be labeled with the name and organizational affiliation of the filer, and the name of the word processing program used to create the document. In the alternative, comments may be submitted electronically to the following electronic mail address: *esignstudy__utilnot@ntia.doc.gov*. Comments submitted via electronic mail also should be submitted in one or more of the formats specified above.

FOR FURTHER INFORMATION CONTACT: For questions about this request for comment, contact: Josephine Scarlett, Attorney, Office of the Chief Counsel, NTIA, 14th Street and Constitution Ave., NW., Washington, DC 20230, telephone (202) 482–1816 or electronic mail: *jscarlett@ntia.doc.gov*. Media inquiries should be directed to the Office of Public Affairs, National Telecommunications and Information Administration, at (202) 482–7002.

SUPPLEMENTARY INFORMATION:

Background: Electronic Signatures in Global and National Commerce Act

Congress enacted the Electronic Signatures in Global and National Commerce Act, Pub. L. No. 106–229, 114 Stat. 464 (2000), to facilitate the use of electronic records and signatures in interstate and foreign commerce and to remove uncertainty about the validity of contracts entered into electronically. Section 101 requires, among other things, that electronic signatures, contracts, and records be given legal effect, validity, and enforceability. Sections 103(a) and (b) of the Act provides that the requirements of section 101 shall not apply to contracts and records governed by statutes and regulations regarding: court documents; probate and domestic law matters; state commercial law; consumer law covering utility services, residential default and foreclosure notices, and insurance benefits cancellation notices; product recall notices; and hazardous materials documents.

The statutory language providing for an exception to section 101 of ESIGN for utility cancellation or disconnection notices is found in section 103(b) of the Act:

Sec. 103. [15 U.S.C. 7003] Specific Exceptions.

* * * *

(b) Additional Exceptions.—The provisions of section 101 shall not apply to—

(2) any notice of—

(A) the cancellation or termination of utility services (including water, heat, and power);

* * * *

The statutory language requiring the Assistant Secretary for Communications and Information to submit a report to Congress on the results of the evaluation of the section 103 exceptions to the ESIGN Act is found in section 103(c)(1) of the Act as set forth below.

(c) Review of Exceptions.—

(1) Evaluation required.— The Secretary of Commerce, acting through the Assistant Secretary for Communications and Information, shall review the operation of the exceptions in subsections (a) and (b) to evaluate, over a period of 3 years, whether such exceptions continue to be necessary for the protection of consumers. Within 3 years after the date of enactment of this Act, the Assistant Secretary shall submit a report to Congress on the results of such evaluation.

Utility Service Cancellation Notices

The rates, terms and conditions of service provided by electric, gas, telephone, water and sewer companies are governed by federal and state laws and regulations. These federal, state, and municipal regulations prescribe methods and procedures that govern how utility companies make voluntary and involuntary terminations of service to customers, and how notices of

[1] Comments submitted in response to the **Federal Register** notices requesting comment on the other exceptions to ESIGN will be considered as part of the same section 103 evaluation and not as part of a separate review of the Act. Notices have been published on the following exceptions to ESIGN: court, family law, and hazardous materials documents; wills; product recall, housing default, and insurance cancellation notices; and contracts governed by state uniform commercial law. *See* 67 Fed.Reg. 56277, 56279, 59828, 61599, 63379, 69201, 75849, and 78421.

pending terminations are provided to customers. On the federal level, there are regulations that instruct utility companies on the procedure for notifying utility customers of pending cancellations of service. The Federal Communications Commission's (FCC) regulations, for example, contain several provisions that direct long distance telephone service providers to give their customers written notice upon discontinuance of service. The FCC's rules require that all domestic carriers apply to the FCC for authority to discontinue service, and, as part of that application, to notify all affected customers of a planned discontinuance of service and submit a copy of the application to the public utility commission and to the government of the state in which the discontinuance is proposed, as well as to the Secretary of Defense. 47 CFR 63.71(a). Non-dominant international carriers are also required to provide written notice to customers at least 60 days prior to discontinuance of service. *See* 47 CFR 63.19. Although the FCC's rules require written notice, they do not specifically prohibit the use of electronic methods to transmit the notice to customers.

The FCC's rules allow some transactions and communications to be made by electronic means, including electronic posting of the terms and conditions of service that describe the procedure for termination of service. The FCC allows telephone companies to use electronic methods and signatures for letters of agency, and authorizations or verification of a subscriber's request to change his or her preferred carrier selection. *See* 47 CFR 64.1130. These rules require that letters of agency submitted with an electronic signature include the consumer disclosures required by section 101(c) of ESIGN. 47 CFR 64.1130(i). In the *Domestic Detariffing Order*[2] and the *International Detariffing Order*[3], the FCC also allowed long distance carriers to provide information regarding rates and conditions of service on Internet web sites rather than through traditional tariff filings. *See* 47 CFR § 42.10, 61.72. As part of the congressional energy conservation policies adopted in the early and mid 1990s, Congress enacted special rules and standard procedures for utility companies to follow during terminations of gas and electric service. *See* 15 U.S.C. 3204; 16 U.S.C. 2625(g). These rules refer to procedures that are to be prescribed by state utility and regulatory commissions directing utility service providers to provide reasonable prior notice to consumers of pending termination or discontinuance of service and to allow consumers an opportunity to dispute the reasons for the termination. *Id.* In general, states and municipal governments have adopted regulations to govern disconnection notice procedures for utility companies.

In some cases, these regulations also apply to municipal utilities as well as privately-owned companies. For example, Nebraska's regulations provide that: ''[n]o municipal utility owned and operated by a village furnishing water, natural gas or electricity at retail . . . shall discontinue service to any domestic subscriber for nonpayment of any past due account unless such utility first gives written notice by mail to any subscriber at least seven days prior to termination.'' Neb.Rev.Stat.Ann. § 70–1603 (2002). Under this regulation, notice must be given to the consumer by first-class mail or in person and service must continue for at least seven days after notice has been given. *Id.* at § 70–1605. The amount of time for each notice varies among the states; however, most states require written notice of utility service disconnection to be given in advance by mail or in person.[4]

The ESIGN exception for utility cancellation notices means utility companies are not allowed to provide notices of cancellation of gas, water, telephone, or electric service through electronic means or using an electronic signature. Approximately 40 states have adopted Uniform Electronic Transactions Act (UETA) laws, which allows the states to be removed from the operation of ESIGN by adopting their own electronic transactions law in accordance with section 102(a)(1) of ESIGN. *See* National Conference of Commissioners on Uniform State Laws at *http://www.nccusl.org/nccusl/LegislativeByState.pdf*. The utility cancellation notice exception has not been incorporated into all state uniform electronic transactions laws, and therefore, electronic notice of utility cancellation may be allowed by some states. The absence of an exception in a state UETA law for utility cancellation notices does not automatically make these documents subject to that law. In some cases, the state or municipal utility laws and regulations control the format and procedure for providing notice to consumers of cancellation of utility services and may authorize formats other than paper writings.

The ESIGN section 103 evaluation of the utility cancellation notices exception is intended to evaluate the current status of the law and procedure regarding this issue in preparation for a report to Congress on whether this exception remains necessary to protect consumers. This evaluation is not a review or analysis of laws relating to these documents for the purpose of recommending that Congress draft legislation or propose changes to those laws, but to advise Congress of the current state of law, practice, and procedure regarding this issue since the passage of the ESIGN Act in 2000. Comments filed in response to this Notice should not be considered to have a connection with or impact on specific, ongoing federal and state court proceedings or administrative rulemaking proceedings concerning utility cancellation notices.

Invitation to Comment

NTIA requests that interested parties, including members of the bar, courts and consumer representatives, submit written comments on any issue of fact, law, or policy that may assist in the evaluation required by section 103(c). We invite comments from all parties that may be affected by the removal of the utility cancellation notices exception from the ESIGN Act including, but not limited to, state agencies and organizations, national and state bar associations, consumer advocates, and utilities and administrative law practitioners. The comments will assist NTIA in evaluating the potential impact of the removal of this exception from ESIGN on consumers, utility companies, legal professionals, and state electronic transactions laws. The following questions are intended to provide guidance as to the specific subject areas to be examined as a part of the evaluation. Commenters are invited to discuss any relevant issue, regardless of whether it is identified below.

1. What methods, if any, are available to protect utility service customers if the utility cancellation notices exception is removed from the ESIGN Act?

2. Discuss state and municipal utility regulation and consumer protection

[2] Second Report and Order, 11 FCC Rcd 20,730 (1996) (*Domestic Detariffing Order*); *stay granted*, *MCI Telecommunications Corp. v. FCC*, No. 96-1459 (D.C. Cir. Feb. 13, 1997); Order on Reconsideration, 12 FCC Rcd 15,014 (1997)(Domestic Detariffing Order on Reconsideration); Second Order on Reconsideration and Erratum, 14 FCC Rcd 6004 (1999)(*Domestic Detariffing Second Order on Reconsideration*); *stay lifted and aff'd*, *MCI WorldCom, Inc., et al. v. FCC*, 209 F.3d 760 (D.C. Cir. April 28, 2000), Memorandum Report and Order, DA 00-2586 (CCB, rel. Nov. 17, 2000)(*Domestic Transition Order*).

[3] In the Matter of 2000 Biennial Regulatory Review, Policy Concerning the International, Interexchange Marketplace, Report and Order, 16 FCC Rcd 10,647 (2001)(International Detariffing Order).

[4] Compare New Hampshire, N.H.Rev. Stat.Ann. § 363.B:1(2002) (10days) and New York, N.Y.[Pub.Serv.] § 34.1(2002) (15days).

laws that require written notice to consumers for cancellation of telephone, water, gas, or electric utility services.

3. Discuss state and municipal utility regulations, laws, or ordinances that allow utilities to send electronic notices to consumers for cancellation or termination of telephone, water, gas or electric utility services.

4. How would the removal of the utility cancellation notices exception to ESIGN affect consumers? How would the removal of the exception affect the provision of notice by utility companies to their customers? Please discuss.

5. What effect would the removal of the exception have on the current municipal, state, and federal policies concerning notice of utility service cancellations?

6. If the ESIGN Act is amended to eliminate the utility cancellation notice exception, what other changes, if any, are required to maintain consumer protection laws? What changes would be necessary, if any, to maintain current state and Federal policies concerning the content and timing of utility cancellation notices?

7. What are the benefits for utility customers, and utility companies that may result from electronic notice of cancellation of utility services? For example, would electronic notice provide customers with additional time to correct conditions or circumstances that led to the cancellation?

8. List any unique issues surrounding the delivery, timing, authentication, privacy, of utility cancellation notices that can and should be resolved prior to removal of the exception from the Act.

9. State whether municipalities, states, or utility companies have developed electronic notification procedures for the transmission of utility service information.

10. Discuss current electronic methods that are used to provide information to consumers regarding utility services (e.g., conditions of service or rate information). In these instances, discuss the consumer protection mechanisms that are employed by utility companies to transmit service or rate information to customers. Also discuss the following:

a. receipt verification procedures;

b. updated regulations that reflect electronic signature technologies; and

c. regulations that require the retention of paper copies of the notice.

Please provide copies of studies, reports, opinions, research or other empirical data referenced in the responses.

Dated: January 23, 2003.

Kathy D. Smith,

Chief Counsel, National Telecommunications and Information Administration.

[FR Doc. 03–1921 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–60–S

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Establishment of Import Limits for Certain Wool and Man-Made Fiber Textile Products Produced or Manufactured in Belarus

January 21, 2003.

AGENCY: Committee for the Implementation of Textile Agreements (CITA).

ACTION: Issuing a directive to the commissioner of customs establishing limits.

EFFECTIVE DATE: January 28, 2003.

FOR FURTHER INFORMATION CONTACT: Naomi Freeman, International Trade Specialist, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 482-4212. For information on the quota status of these limits, refer to the Quota Status Reports posted on the bulletin boards of each Customs port, call (202) 927-5850, or refer to the U.S. Customs Web site at http://www.customs.gov. For information on embargoes and quota re-penings, refer to the Office of Textiles and Apparel website at http://otexa.ita.doc.gov.

SUPPLEMENTARY INFORMATION:

Authority: Section 204 of the Agricultural Act of 1956, as amended (7 U.S.C. 1854); Executive Order 11651 of March 3, 1972, as amended.

The Bilateral Textile Memorandum of Understanding dated January 10, 2003 between the Governments of the United States and Belarus establishes limits for the period January 1, 2003 through December 31, 2003. This notice cancels and supercedes the notice published on December 30, 2002 (67 FR 79571).

These limits may be revised if Belarus becomes a member of the World Trade Organization (WTO) and the United States applies the WTO agreement to Belarus.

In the letter published below, the Chairman of CITA directs the Commissioner of Customs to establish the limits.

A description of the textile and apparel categories in terms of HTS numbers is available in the CORRELATION: Textile and Apparel Categories with the Harmonized Tariff Schedule of the United States (see Federal Register notice 68 FR 1599, published on January 13, 2003).

James C. Leonard III,

Chairman, Committee for the Implementation of Textile Agreements.

Committee for the Implementation of Textile Agreements

January 21, 2003.

Commissioner of Customs,

Department of the Treasury, Washington, DC 20229.

Dear Commissioner: Pursuant to section 204 of the Agricultural Act of 1956, as amended (7 U.S.C. 1854); Executive Order 11651 of March 3, 1972, as amended; this directive cancels and supercedes the directive issued to you on December 23, 2002. You are directed to prohibit, effective on January 28, 2003, entry into the United States for consumption and withdrawal from warehouse for consumption of textiles and textile products in the following categories, produced or manufactured in Belarus and exported during the twelve-month period beginning on January 1, 2003 and extending through December 31, 2003:

Category	Twelve-month restraint limit
622	9,100,000 square meters of which not more than 1,500,000 square meters shall be in Category 622-L [1].
435	66,000 dozen.
448	34,000 dozen.

[1] Category 622-L: only HTS numbers 7019.51.9010, 7019.52.4010, 7019.52.9010, 7019.59.4010, and 7019.59.9010.

Products in Categories 622 and 622-L exported during 2002 shall be charged to the applicable category limit and sublimit for that year (see directive dated October 19, 2001) to the extent of any unfilled balance. In the event the limit and sublimit established for that period have been exhausted by previous entries, such products shall be charged to the limit and sublimit set forth in this directive.

The limits set forth above are subject to adjustment pursuant to the current bilateral agreement between the Governments of the United States and Belarus.

This limits may be revised if Belarus becomes a member of the World Trade Organization (WTO) and the United States applies the WTO agreement to Belarus.

In carrying out the above directions, the Commissioner of Customs should construe entry into the United States for consumption to include entry for consumption into the Commonwealth of Puerto Rico.

The Committee for the Implementation of Textile Agreements has determined that this action falls within the foreign affairs exception of the rulemaking provisions of 5 U.S.C. 553(a)(1).

Sincerely,

James C. Leonard III,

Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc.03–1865 Filed 1–27–03; 8:45 am]

BILLING CODE 3510–DR–S

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

eGrants Orientation Conference Calls for Organizations Interested in Applying for an AmeriCorps*National Program Grant

AGENCY: Corporation for National and Community Service.

ACTION: Notice of eGrants Orientation Conference Calls for AmeriCorps*National new applicants.

SUMMARY: The Corporation is offering eGrants Orientation Conference Calls for organizations interested in applying for an AmeriCorps*National program grant. These training telcons will provide an orientation on the basic functions and operations of the eGrants system. We will familiarize organizations with the technical steps of preparing and submitting an application using the eGrants system. For more information on the eGrants system, *see: http://www.nationalservice.org/egrants/index.html.*

Audience: Nonprofit organizations applying for an AmeriCorps*National program grant using the eGrants system.

Dates and Times of Calls: The calls will take place on:

February 3rd, 1 pm–3 pm est;
February 7th, 1:30 pm–3:30 pm est;
February 19th, 1 pm–3 pm est;
February 20th, 2 pm–4 pm est.

All calls will cover the same content. Please note that there is a limit of 8 participant slots per call. Each organization may sign-up for one slot.

Process and Deadline for Registering for a call: Select one of the call dates specified above, then contact Sueko Kumagai via e-mail *(skumagai@cns.gov)* or phone (202–606–5000 ext. 418) with your selected date. You must respond no later than five days prior to your selected call to reserve a slot on one of the calls.

FOR FURTHER INFORMATION CONTACT: For further information, contact one of the following: Sueko Kumagai at 202–606–5000 ext. 418; or Lois Nembhard at 202–606–5000 ext. 299.

Dated: January 22, 2003.

John Foster-Bey,

*Director, AmeriCorps*State/National.*

[FR Doc. 03–1805 Filed 1–27–03; 8:45 am]

BILLING CODE 6050–$$–P

DEPARTMENT OF DEFENSE

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

Department of the Air Force

Notice of Intent to Prepare a Joint Environmental Impact Statement and Environmental Impact Report

AGENCIES: Department of the Air Force, Department of Housing and Urban Development, City of Hawthorne, and the City of El Segundo.

ACTION: Notice of intent to prepare a joint Environmental Impact Statement and Environmental Impact Report for the proposed Los Angeles Air Force Base land conveyance, construction and development.

SUMMARY: The U.S. Department of the Air Force, lead agency under the National Environmental Policy Act (NEPA) and the City of El Segundo, California, lead agency under the California Environmental Quality Act (CEQA), announce their intent to prepare a joint draft Environmental Impact Statement (EIS)/Environmental Impact Report (EIR) for the proposed land conveyance, construction, development and consolidation of the Los Angeles Air Force Base (LAAFB).

The Air Force will have primary responsibility to ensure that the joint EIS/EIR complies with NEPA (42 U.S.C. 4321 *et. seq.*); the Council on Environmental Quality (CEQ) regulations that implement the procedural provisions of NEPA (40 CFR parts 1500–1508); and the Air Force procedures for implementing NEPA, Air Force Instruction (AFI) 32–7061, Environmental Impact Analysis Process (EIAP), as promulgated at 32 Code of Federal Regulations part 989.

The City of Hawthorne, California will be a cooperating agency for the joint EIS/EIR, having responsibility for any applications concerning Federal-funding programs administered by HUD, assume responsibility for environmental review, decision-making and actions that would otherwise apply to HUD under NEPA in accordance with 24 CFR part 58. The City of El Segundo shall serve as the agency point of contact for receipt of all comments pertaining to the EIS/EIR and will have primary responsibility for EIS/EIR compliance with CEQA, in accordance with the California Public Resources Code (PRC 21000 *et seq.*) and the California Code of Regulations (14 CCR 15000 *et seq.*).

FOR FURTHER INFORMATION CONTACT: *Air Force:* Mr. Jason Taylor, Environmental Specialist, 61 ABG/CEZV, 2420 Vela Way, Suite 1467, Los Angeles Air Force Base, El Segundo, CA, 90245–4659; fax (310) 363–1595.

City of El Segundo: Mr. Paul Garry, Senior Planner, City of El Segundo, Department of Community, Economic, and Development Services, 350 Main Street., El Segundo, California, 90245 (310) 524–2342.

SUPPLEMENTARY INFORMATION: Section 2861 of the Floyd D. Spence National Defense Authorization Act for Fiscal Year 2001, as amended by section 2841 of the Bob Stump National Defense Authorization Act for Fiscal Year 2003, authorizes the conveyance of parcels of real property at Los Angeles Air Force Base in exchange for the design and construction of facilities meeting seismic and safety design standards for Los Angeles, California, to consolidate mission and support functions at the base. A draft Environmental Assessment (EA) was prepared in September 2002 in accordance with the NEPA and the CEQ regulations implementing NEPA to analyze the potential environmental consequences of the land conveyance and seismic upgrade. As a result of public comments in received on the EA in October 2002, the Air Force has entered into an agreement with the Cities of El Segundo and Hawthorne, California to revise the proposed action and to prepare a joint EIS/EIR on the project.

The proposed action would include, among other components, the construction of 560,000 square feet of administrative and special use facilities for the Air Force on Area B (located within the City of El Segundo); non-Air Force development of 975 condominium residential units on Area A (City of El Segundo annex to City of Hawthorne pending), and non-Air Force development of 333 condominium residential units on the Lawndale Annex (City of Hawthorne). No changes would occur to the Sun Valley property located in the City of Los Angeles.

Alternatives include a reduced density alternative at the conveyed, redeveloped properties; a retail-commercial alternative at the conveyed, redeveloped properties; a renovation alternative, using traditional Military Construction (MILCON) funding to implement the land conveyance and development project; and the no-action alternative, under which the Air Force will continue to operate current facilities with limited MILCON and facility alteration/repair projects.

A scoping meeting will be held to identify significant issues to be addressed in the EIS/EIR. To ensure that

a full range of issues related to this proposed action are identified and addressed, scoping comments are invited from all interested parties. A public scoping meeting is scheduled to be held, as follows:

Date: Thursday, January 30, 2003.

Time: 8 a.m.

Place: City Council Chambers, 350 Main Street, El Segundo, California.

Written comments pertaining to the proposed action will be accepted throughout the EIS/EIR planning process. However, to ensure proper consideration in preparation of the draft EIR/EIS, scoping comments should be received within 15 days of the publication of this notice. The draft EIS/EIR is planned for publication and distribution in February 2003. Copies may be obtained, upon request, from the Air Force point of contact.

Pamela D. Fitzgerald,

Air Force Federal Register Liaison Officer.

[FR Doc. 03–1797 Filed 1–27–03; 8:45 am]

BILLING CODE 5001–05–P

DEPARTMENT OF EDUCATION

Submission for OMB Review; Comment Request

AGENCY: Department of Education.

SUMMARY: The Leader, Regulatory Management Group, Office of the Chief Information Officer invites comments on the submission for OMB review as required by the Paperwork Reduction Act of 1995.

DATES: Interested persons are invited to submit comments on or before February 27, 2003.

ADDRESSES: Written comments should be addressed to the Office of Information and Regulatory Affairs, Attention: Lauren Wittenberg, Desk Officer, Department of Education, Office of Management and Budget, 725 17th Street, NW., Room 10235, New Executive Office Building, Washington, DC 20503 or should be electronically mailed to the internet address *Lauren.Wittenberg@omb.eop.gov*.

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. OMB may amend or waive the requirement for public consultation to the extent that public participation in the approval process would defeat the purpose of the information collection, violate State or Federal law, or substantially interfere with any agency's ability to perform its statutory obligations. The Leader, Regulatory Management Group, Office of the Chief Information Officer, publishes that notice containing proposed information collection requests prior to submission of these requests to OMB. Each proposed information collection, grouped by office, contains the following: (1) Type of review requested, *e.g.* new, revision, extension, existing or reinstatement; (2) Title; (3) Summary of the collection; (4) Description of the need for, and proposed use of, the information; (5) Respondents and frequency of collection; and (6) Reporting and/or Recordkeeping burden. OMB invites public comment.

Dated: January 23, 2003.

John D. Tressler,

Leader, Regulatory Management Group, Office of the Chief Information Officer.

Federal Student Aid

Type of Review: New Collection.

Title: Teacher Cancellation Low Income Directory (JS).

Frequency: Annually.

Affected Public: Individuals or household, State, Local, or Tribal Gov't, SEAs or LEAs.

Reporting and Recordkeeping Hour Burden:

Responses: 1.

Burden Hours: 6983.

Abstract: There are 57 State Agencies that contribute to the development of a directory of elementary and secondary schools which qualify for the teacher cancellation benefit. The directory allows post-secondary institutions to determine whether or not a teacher who received a Federal Perkins Loan, Direct loan, or Federal Family Education Loan at their school is eligible to receive a loan cancellation as provided under Title I of the Elementary and Secondary Education Act of 1965.

Written requests for information should be addressed to Vivian Reese, Department of Education, 400 Maryland Avenue, SW, Room 4050, Regional Office Building 3, Washington, DC 20202–4651 or directed to her e-mail address *Vivian.Reese@ed.gov*. Requests may also be faxed to (202) 708–9346.

Please specify the complete title of the information collection when making your request.

Comments regarding burden and/or the collection activity requirements should be directed to Joseph Schubart at his e-mail address *Joe.Schubart@ed.gov*. Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. 03–1897 Filed 1–27–03; 8:45 am]

BILLING CODE 4000–01–U

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. IC03–539–000, FERC–539]

Commission Information Collection Activities, Proposed Collection; Comment Request; Extension

January 22, 2003.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice.

SUMMARY: In compliance with the requirements of Section 3506(c)(2)(a) of the Paperwork Reduction Act of 1995, 44 U.S.C. 3506(c)(2)(A), the Federal Energy Regulatory Commission (Commission) is soliciting public comment on the specific aspects of the information collection described below.

DATES: Comments on the collection of information are due by March 24, 2003.

ADDRESSES: Copies of the proposed collection of information can be obtained from Michael Miller, Office of the Chief Information Officer, CI–1, 888 First Street NE., Washington, DC 20426. Comments may be filed either in paper format or electronically. Those parties filing electronically do not need to make a paper filing.

For paper filings, the original and 14 copies of such comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 and refer to Docket No. IC03–539–000.

Documents filed electronically via the Internet must be prepared in WordPerfect, MS Word, Portable Document Format, or ASCII format. To file the document, access the Commission's Web site at *http://www.ferc.gov* and click on ''Make an E-filing,'' and then follow the instructions for each screen. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgment to the sender's e-mail address upon receipt of comments. User assistance for electronic filings is available at 202–502–8258 or by e-mail to *efiling@ferc.gov* Comments should not be submitted to the e-mail address.

All comments may be viewed, printed or downloaded remotely via the Internet through FERC's homepage using the

FERRIS link. For user assistance, contact *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676 or for TTY, contact (202)502–8659.

FOR FURTHER INFORMATION CONTACT: Michael Miller may be reached by telephone at (202)502–8415, by fax at (202)208–2425, and by e-mail at *michael.miller@ferc.gov*.

SUPPLEMENTARY INFORMATION: The information collected under the requirements of FERC–539 ''Gas Pipeline Certificates: Import/Export'' (OMB No. 1902–0062) is used by the Commission to implement the statutory provisions of Section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717–717w. Section 3 requires prior authorization before reporting or importing natural gas from or to the United States. Section 3 authorizes the Commission to grant an application, in whole or in part, with modifications and upon terms and conditions as the Commission may find necessary or appropriate. The 1992 amendments to Section 3 of the NGA concern the importation or exportation from/to a nation which has a free trade agreement with the United States. With the passage of both the North American Free Trade Agreement and the Canadian Free Trade Agreement, the construction, operation and siting of import or export facilities are also the subject of the Commission's regulatory focus.

In Order No. 608, the Commission created voluntary procedures whereby prospective applicants could use a collaborative process to resolve significant issues prior to filing an application. This collaborative process allows applicants and interested parties to come together and come to mutual agreements that may help to defuse some of the controversial issues which may otherwise arise once an application has been filed with the Commission. The pre-filing consultation process combines efforts to address NGA issues with the National Environmental Policy Act (NEPA) review process into a single pre-filing collaborative process that also includes the administrative processes associated with the Clean Water Act, the National Historic Preservation Act, the Endangered Species Act and other relevant statutes. Combining the pre-filing consultation and environmental review into a single pre-filing process simplifies and expedites the authorization of gas facilities and services.

The Commission uses the information to determine the appropriateness of the proposed facilities and their location. The determination involves among other things, an examination of adequacy of design, cost, reliability, redundancy and environmental acceptability. This information is necessary for the Commission to make a determination that the facilities and location are consistent with the public interest. The Commission implements these filing requirements in the Code of Federal Regulations (CFR) under 18 CFR part 153.

Action: The Commission is requesting a three-year extension of the current expiration date, with no changes to the existing collection of data.

Burden Statement: Public reporting burden for this collection is estimated as:

Number of respondents annually (1)	Number of responses per respondent (2)	Average burden hours per response (3)	Total Annual burden hours (1)×(2)×(3)
12	1	241	2,886

Estimated cost burden to respondents: 2,886 hours / 2,080 hours per year × $117,041 per year = $162,394. The cost per respondent is equal to $ 13,533.

The reporting burden includes the total time, effort, or financial resources expended to generate, maintain, retain, disclose, or provide the information including: (1) Reviewing instructions; (2) developing, acquiring, installing, and utilizing technology and systems for the purposes of collecting, validating, verifying, processing, maintaining, disclosing and providing information; (3) adjusting the existing ways to comply with any previously applicable instructions and requirements; (4) training personnel to respond to a collection of information; (5) searching data sources; (6) completing and reviewing the collection of information; and (7) transmitting, or otherwise disclosing the information.

The estimate of cost for respondents is based upon salaries for professional and clerical support, as well as direct and indirect overhead costs. Direct costs include all costs directly attributable to providing this information, such as administrative costs and the cost for information technology. Indirect or overhead costs are costs incurred by an organization in support of its mission. These costs apply to activities which benefit the whole organization rather than any one particular function or activity.

Comments are invited on: (1) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information will have practical utility; (2) 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; (3) ways to enhance the quality, utility and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on those who are to respond, including 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.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1927 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP02–39–005]

Columbia Gulf Transmission Company; Notice of Filing of Report

January 22, 2003.

Take notice that, on January 14, 2003, Columbia Gulf Transmission Company (Columbia Gulf) tendered for filing its report after one year's experience of parking and lending service under Rate Schedule PAL. Columbia Gulf's states that its report indicates that there were no PAL transactions involving multiple points during the first year of service.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Section 385.211 of the Commission's Rules and Regulations. All such protests must 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 proceedings. This filing is available

for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. Comments, protests and interventions may be filed electronically via the Internet in lieu of paper. For Assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link.

Comment date: January 29, 2003.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1940 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP03–188–001]

East Tennessee Natural Gas Company; Notice of Compliance Filing

January 22, 2003.

Take notice that on January 15, 2003, East Tennessee Natural Gas Company (East Tennessee) tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, Sub Twenty-Fifth Revised Sheet No. 4, to be effective January 6, 2003.

East Tennessee states that the purpose of this filing is to comply with the directives of the Commission's Order dated January 3, 2003, in Docket No. RP03–188–000. The January 3 Order directed East Tennessee to file, within twenty days, a revised Twenty-Fifth Revised Sheet No. 4 to reflect the maximum daily volumetric firm rate separately for each of the three expansion projects (Rocky Top, Gateway and Murray) and the non-expansion FT–A rate. In this compliance filing, East Tennessee hereby submits the revised tariff sheet required by the January 3 Order.

East Tennessee states that copies of its filing have been mailed to all affected customers of East Tennessee and interested state commissions, and all parties on the Commission's official service list in this proceeding.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Section 385.211 of the Commission's Rules and Regulations. All such protests must be filed in accordance with 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. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For Assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link.

Protest Date: January 27, 2003.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1941 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP00–341–004]

Egan Hub Partners, L.P.; Notice of Compliance Filing

January 22, 2003.

Take notice that on January 15, 2003, Egan Hub Partners, L.P. (Egan Hub) tendered for filing as part of its FERC Gas Tariff, Original Volume No. 1, certain revised tariff sheets identified in Appendix A to the filing proposed to be effective on December 24, 2002.

Egan Hub states that the purpose of this filing is to conform the pagination, supersession and/or content of the referenced tariff sheets to reflect the Commission's acceptance of tariff revisions in Docket Nos. RP00–341–002, RP02–264–000, RP02–264–001 and RP02–491–000. Egan Hub states that the tariff sheets filed herein contain only those changes approved by the orders issued in the referenced dockets.

Egan Hub states that copies of its filing have been mailed to all affected customers and interested state commissions and to all parties on the official service list.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Section 385.211 of the Commission's Rules and Regulations. All such protests must be filed in accordance with 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. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For Assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link.

Protest Date: January 27, 2003.

Magalie R. Salas,]

Secretary.

[FR Doc. 03–1939 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission El Dorado Irrigation District California; Notice of Public Meetings

January 22, 2002.

The Federal Energy Regulatory Commission (Commission) is reviewing the application for a new license for the El Dorado Project (FERC No. 184), filed on February 22, 2000. The El Dorado Project, licensed to the El Dorado Irrigation District (EID), is located on the South Fork American River, in El Dorado, Alpine, and Amador counties, California. The project occupies lands of the Eldorado National Forest.

The EID, several State and Federal agencies, and several non-governmental agencies are working collaboratively with a facilitator to resolve certain issues relevant to this proceeding. These meetings are a part of that collaborative process. Meetings will be held as follows:

February 10 Plenary Meeting—9 am–4 pm; February 11 Plenary Meeting—9 am–4 pm; and February 12 Plenary Meeting—9 am–4 pm.

We invite the participation of all interested governmental agencies, non-

governmental organizations, and the general public in these meetings.

All meetings will be held in the El Dorado Board of Directors Meeting Room, located at EID Headquarters, 2890 Mosquito Road, Placerville, California.

For further information, please contact Elizabeth Molloy at (202) 502–8771 or John Mudre at (202) 502–8902.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1937 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP99–176–077]

Natural Gas Pipeline Company of America; Notice of Negotiated Rates

January 22, 2003.

Take notice that on January 15, 2003, Natural Gas Pipeline Company of America (Natural) tendered for filing to become part of its FERC Gas Tariff, Sixth Revised Volume No. 1, First Revised Sheet No. 26W.09 to be effective January 15, 2003.

Natural states that the purpose of this filing is to terminate, effective January 15, 2003, an existing negotiated rate transaction between Natural and Aquila Merchant Services, Inc., formerly known as Aquila Energy Marketing Corp., under Natural's Rate Schedule ITS approved in Docket No. RP99–176–060 and implemented pursuant to Section 49 of the General Terms and Conditions of Natural's Tariff.

Natural states that copies of the filing are being mailed to all parties set out on the Commission's official service list in Docket No. RP99–176.

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, NE., Washington, DC 20426, in accordance with Sections 385.314 or 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed in accordance with 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. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For Assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link.

Comment date: January 27, 2003.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1942 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EC03–46–000, et al.]

El Paso Corporation, et al.; Electric Rate and Corporate Filings

January 17, 2003.

The following filings have been made with the Commission. The filings are listed in ascending order within each docket classification.

1. El Paso Corporation, Limestone Electron Trust, El Paso Tennessee Pipeline Co., El Paso Chaparral Holding Company, El Paso Chaparral Investor, L.L.C., El Paso Chaparral Holding II Company, Chaparral Investors, L.L.C., Mesquite Investors, L.L.C.

[Docket No. EC03–46–000]

Take notice that on January 13, 2003, El Paso Corporation (El Paso), Limestone Electron Trust (Limestone) El Paso Tennessee Pipeline Co. (El Paso Tennessee), El Paso Chaparral Holding Company (Chaparral Holding), El Paso Chaparral Investor, L.L.C. (El Paso Chaparral), El Paso Chaparral Holding II Company (Chaparral Holding II), Chaparral Investors, L.L.C. (Chaparral) and Mesquite Investors, L.L.C. (Mesquite) (jointly, Applicants) filed with the Federal Energy Regulatory Commission an application pursuant to Section 203 of the Federal Power Act seeking authorization to transfer indirect control over the jurisdictional facilities of Chaparral's indirect subsidiaries. Applicants also request expedited consideration of this Application.

Comment Date: February 3, 2003.

2. Dynegy Inc.

[Docket No. EC03–47–000 and ES03–20–000]

Take notice that on January13, 2003, Dynegy Inc. (Dynegy), on behalf of certain of its public utility subsidiaries (Applicants), filed with the Federal Energy Regulatory Commission an application pursuant to Section 203 of the Federal Power Act (FPA) for authorization of a disposition of jurisdictional facilities pursuant to an intra-corporate reorganization. Specifically, Dynegy seeks authorization to create one or more new intermediate holding companies between Dynegy Holdings Inc., and its indirect public utility subsidiaries. Dynegy also requests that the Commission grant Dynegy Power Marketing, Inc., blanket authority pursuant to FPA Section 204 to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person.

Comment Date: February 3, 2003.

3. Midwest Independent Transmission System Operator, Inc.

[Docket No. ER02–1420–005]

Take notice that on January 10, 2003, American Electric Power on behalf of Southwestern Electric Power Company (SWEPCO) and Public Service Company of Oklahoma (PSO), operating companies of the American Electric Power System (collectively AEP) submitted an updated status of their participation in the Midwest ISO.

Comment Date: January 31, 2003.

4. Duke Energy New Albany, LLC

[Docket No. ER02–171–001]

Take notice that on January 14, 2003, Duke Energy New Albany, LLC (Duke New Albany) tendered for filing its triennial market power analysis in compliance with the Commission Order granting it market-based rate authority in Docket No. ER99–1942–000 on April 15, 1999.

Duke New Albany states that copies of this filing were served upon those parties on the official service list.

Comment Date: February 4, 2003.

5. Entergy Services, Inc.

[Docket No. ER02–2014–006]

Take notice that on January 15, 2003, Entergy Services, Inc., on behalf of the Entergy Operating Companies, Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc. (collectively Entergy), filed a revised Attachment Q to its Open Access Transmission Tariff. Attachment Q addresses local transmission constraints on the Entergy transmission

system and provides a process for generators to participate in short-term bulk power markets without the necessity of a system impact study. Entergy requests an effective date thirty days after the date of any final Commission order approving Entergy's revised Attachment Q.

Comment Date: February 5, 2003.

6. NorthWestern Energy, L.L.C.

[Docket No. ER02–2569–001]

Take notice that on January 14, 2003, The Clark Fork and Blackfoot, L.L.C. (TCFB) (formerly named NorthWestern Energy, L.L.C.) tendered for filing an application for an order accepting its FERC Electric Tariff Original Volume No. 1, granting certain blanket approvals, including the authority to sell electricity, capacity, and ancillary services at market-base rates, and waiving certain regulations of the Commission.

TCFB also filed its FERC Electric Tariff Original Volume No. 1, seeking an effective date of February 13, 2003.

Comment Date: February 4, 2003.

7. Entergy Services, Inc.

[Docket No. ER03–59–002]

Take notice that on January 15, 2003, Entergy Services, Inc., on behalf of Entergy New Orleans, Inc., tendered for filing with the Federal Energy Regulatory Commission (Commission), a compliance Interconnection and Operating Agreement with Duke Energy Orleans, LLC, in response to the Commission's December 16, 2002, order in Entergy Services, Inc., 101 FERC ¶ 61,289.

Comment Date: February 5, 2003.

8. Southern California Edison Company

[Docket No. ER03–142–001]

Take notice that on January 15, 2003, Southern California Edison Company (SCE) tendered for filing revised rate sheets for its Transmission Owner Tariff (TO Tariff), FERC Electric Tariff, Substitute First Revised Original Volume No. 6, and for certain of its Existing Transmission Contracts with the Arizona Electric Power Cooperative Inc., the city of Colton, California, and the California Department of Water Resources. The purpose of this filing is to comply with the Federal Energy Regulatory Commission's Order Accepting for Filing and Suspending Proposed Tariff and Contract Amendments and Establishing Hearing and Settlement Judge Procedures dated December 31, 2002 (Southern California Edison Company, 101 FERC ¶ 61,404).

SCE states that copies of this filing were served upon the Service List compiled by the Secretary in this docket.

Comment Date: February 5, 2003.

9. PJM Interconnection, L.L.C.

[Docket No. ER03–406–000]

Take notice that on January 10, 2003, PJM Interconnection, L.L.C. (PJM) submitted for filing amendments to the PJM Open Access Transmission Tariff and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., to establish a new annual auction process for Financial Transmission Rights (formerly Fixed Transmission Rights) and an allocation mechanism for the auction revenues. On January 13, 2003, PJM amended its January 10th filing and make conforming changes to Attachment K of the PJM Tariff consistent with the amendments to the Appendix to Attachment K of the PJM Tariff filed on January 10, 2003.

PJM requests an effective date of March 12, 2003 for the amendments. PJM also states that copies of this filing were served upon all PJM members and each state electric utility regulatory commission in the PJM region.

Comment Date: January 31, 2003.

10. American Transmission Company LLC

[Docket No. ER03–413–000]

Take notice that on January 14, 2003, American Transmission Company LLC (ATCLLC) tendered for filing a Generation-Transmission Interconnection Agreement between ATCLLC and Wisconsin Public Service Corporation. ATCLLC requests an effective date of December 15, 2002.

Comment Date: February 4, 2003.

11. Klondike Wind Power LLC

[Docket No. ER03–416–000]

Take notice that on January 15, 2003, Klondike Wind Power LLC filed with the Federal Energy Regulatory Commission (Commission) a Notice of Succession informing the Commission that on December 19, 2002, the name of West Valley Generation LLC had been changed to Klondike Wind Power LLC in accordance with 18 CFR 35.16.

Comment Date: February 5, 2003.

Standard Paragraph

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). 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. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's Web site at *http://www.ferc.gov* , using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number filed to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866)208–3676, or for TTY, contact (202)502–8659. Protests and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1924 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EG03–37–000, et al.]

FPL Energy North Dakota Wind, LLC, et al.; Electric Rate and Corporate Filings

January 22, 2003.

The following filings have been made with the Commission. The filings are listed in ascending order within each docket classification.

1. FPL Energy North Dakota Wind, LLC

[Docket No. EG03–37–000]

Take notice that on January 17, 2003, FPL Energy North Dakota Wind, LLC (the Applicant), with its principal office at 700 Universe Blvd., Juno Beach, Florida 33408, filed with the Federal Energy Regulatory Commission (the Commission) an application for determination of exempt wholesale generator status pursuant to part 365 of the Commission's regulations.

Applicant states that it is a Delaware limited liability company engaged directly and exclusively in the business of owning and operating an approximately 40 MW wind-powered

generation facility located in LaMoure County, North Dakota. Electric energy produced by the facility will be sold at wholesale.

Comment Date: February 12, 2003.

2. FPL Energy South Dakota Wind, LLC

[Docket No. EG03–38–000]

Take notice that on January 17, 2003, FPL Energy South Dakota Wind, LLC (the Applicant), with its principal office at 700 Universe Blvd., Juno Beach, Florida 33408, filed with the Federal Energy Regulatory Commission (Commission) an application for determination of exempt wholesale generator status pursuant to part 365 of the Commission's regulations.

Applicant states that it is a Delaware limited liability company engaged directly and exclusively in the business of owning and operating an approximately 40 MW wind-powered generation facility located in Hyde County, South Dakota. Electric energy produced by the facility will be sold at wholesale.

Comment Date: February 12, 2003.

3. Arizona Public Service Company

[Docket No. EL03–43–000]

Take notice that on January 16, 2003, Arizona Public Service Corporation (APS) filed with the Federal Energy Regulatory Commission (Commission) a petition for declaratory order requesting the Commission's confirmation that the executed Interconnection and Operating Agreement between APS and Reliant Energy Desert Basin, LLC (Reliant), filed as part of the Settlement Agreement approved in Docket No. ER01–1519–000, provides that Reliant will negotiate the terms and conditions of the transfer to APS of the Desert Basin Switchyard constructed by Reliant to enable the interconnection of its Desert Basin generation facility to APS's transmission system, and thereafter consummate such transfer.

Comment Date: February 14, 2003.

4. California Independent System Operator Corporation, Avista Corporation, Bonneville Power Administration, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., Sierra Pacific Power Company, Arizona Public Service Company, El Paso Electric Company, Public Service Company of New Mexico, Tucson Electric Power Company

[Docket Nos. ER02–1656–000, RT01–35–000, RT02–1–000 and EL02–9–000]

Take notice that on January 8, 2003, the California Independent System Operator Corporation (California ISO), the RTO West Filing Utilities (Avista Corporation, Bonneville Power Administration, Idaho Power Company, NorthWestern Energy (formerly Montana Power Company), Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc. and Sierra Pacific Power Company) and the WestConnect Applicants (Arizona Public Service Company, El Paso Electric Company, Public Service Company of New Mexico and Tucson Electric Power Company) jointly filed a report concerning activities of the Seams Steering Group—Western Interconnection.

The parties prepared a joint filing for administrative convenience only. California ISO is submitting this filing solely in Docket No. ER02–1656–000, RTO West Filing Utilities are submitting this filing solely in Docket No. RT01–35–000, and WestConnect Applicants are submitting this filing solely in Docket Nos. RT02–1–000 and EL02–9–000.

5. Duke Energy Glynn, LLC Georgia Power Company

[Docket No. ER03–390–000]

Take notice that on January 16, 2003, Duke Energy Glynn, LLC (Duke) and Southern Company Services, Inc., as agent for Georgia Power Company (collectively SCS) submitted on January 9, 2003, a Notice of Cancellation. A letter terminating the Interconnection Agreement was omitted. There are no other changes to the filing and the requested effective date remains June 1, 2002.

Comment Date: February 6, 2003.

6. Progress Energy Service Company, on behalf of Progress Energy Carolinas, Inc.

[Docket No. ER03–414–000]

Take notice that on January 15, 2003, Progress Energy Service Company on behalf of Progress Energy Carolinas, Inc., (Progress Carolinas) tendered for filing an executed Facility Interconnection and Operating Agreement (Interconnection Agreement) between Progress Carolinas and Cogentrix of North Carolina, Inc., (Cogentrix). The Interconnection Agreement provides for the interconnection of Cogentrix's generating facility near Roxboro, NC with Progress Carolinas' transmission system.

Progress Carolinas is requesting an effective date of December 16, 2002 for this Interconnection Agreement. Progress Carolinas also states that a copy of the filing was served upon the North Carolina Utilities Commission and the South Carolina Public Service Commission.

Comment Date: February 5, 2003.

6. Progress Energy Service Company on behalf of Progress Energy Carolinas, Inc.

[Docket No. ER03–415–000]

Take notice that on January 15, 2003, Progress Energy Service Company on behalf of Progress Energy Carolinas, Inc., (Progress Carolinas) tendered for filing an executed Facility Interconnection and Operating Agreement (Interconnection Agreement) between Progress Carolinas and Cogentrix of North Carolina, Inc.(Cogentrix). The Interconnection Agreement provides for the interconnection of Cogentrix's generating facility near Southport, NC with Progress Carolinas' transmission system.

Progress Carolinas is requesting an effective date of December 16, 2002 for this Interconnection Agreement. Progress Carolinas also states that a copy of the filing was served upon the North Carolina Utilities Commission and the South Carolina Public Service Commission.

Comment Date: February 5, 2003.

7. Commonwealth Edison Company

[Docket No. ER03–417–000]

Take notice that on January 15, 2003, Commonwealth Edison Company (ComEd) tendered a Notice of Cancellation of Original Service Agreement Nos. 621, 622, 623, 624, 625, 626, 627, 628, 629, 630, 631, and 632 under ComEd's FERC Electric Tariff, Second Revised Volume No. 5. The service agreements were between ComEd and NRG Power Marketing Inc. (NRG) for transmission service related to the Bourbonnais Energy Center.

ComEd requested waiver to permit an cancellation effective date of January 16, 2003 for all the service agreements.

Comment Date: February 5, 2003.

8. Wisconsin Electric Power Company

[Docket No. ER03–420–000]

Take notice that on January 16, 2002, Wisconsin Electric Power Company (Wisconsin Electric) tendered for filing the inputs to the formula rates in Exhibit No.4 of two Generation-Transmission Must Run Agreements with American Transmission Company, LLC (ATLLLC). The inputs are reflected in an updated Exhibit No. 4.4 for Wisconsin Electric's Oak Creek Power Plant and the Presque Isle and Upper Peninsula of Michigan Hydroelectric Plants. By the terms of the Must Run

Agreements, the inputs to the formula rate tendered for filing took effect on January 1, 2003. As such, Wisconsin Electric requests that the updates to Exhibit Nos. 4.4 of the Must Run Agreements be made effective on January 1, 2003. An update of Exhibit 2 for Presque Isle Power Plant to provide missing information is also included.

Wisconsin Electric states that copies of this filing have been provided to ATCLLC.

Comment Date: February 6, 2003.

9. Midwest Independent Transmission System Operator, Inc.

[Docket No. ER03–422–000]

Take notice that on January 16, 2003, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) tendered for filing proposed revisions in order to clarify certain language in Section B Subsection 2 of Schedule 10 of the Midwest ISO Open Access Transmission Tariff, FERC Electric Tariff, Second Revised Volume No. 1. Applicant requests an effective date of January 17, 2003.

The Midwest ISO has requested waiver of the requirements set forth in 18 CFR 385.2010. The Midwest ISO has electronically served a copy of this filing, with attachments, upon all Midwest ISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, the Midwest ISO Advisory Committee participants, Policy Subcommittee participants, as well as all state commissions within the region. In addition, the filing has been electronically posted on the Midwest ISO's Web site at www.midwestiso.org under the heading ''Filings to FERC'' for other interested parties in this matter.

Comment Date: February 6, 2003.

10. Southern California Edison Company

[Docket No. ER03–424–000]

Take notice that on January 17, 2003, Southern California Edison Company (SCE), tendered for filing a Notice of Cancellation of FERC Electric Tariff, Original Volume No. 5 Service Agreement No. 15. SCE requests that the Notice of Cancellation become effective January 1, 2003.

SCE states that notice of the proposed cancellation has been served upon the Public Utilities Commission of the State of California and Mountainview Power Company.

Comment Date: February 7, 2003.

11. Progress Energy Service Company on behalf of Progress Energy Florida

[Docket No. ER03–425–000]

Take notice that on January 17, 2003,Progress Energy Service Company on behalf of Progress Energy Florida (Progress Florida) tendered for filing an executed Shady Hills Facility Parallel Operation Agreement between Progress Florida and Florida Power & Light Company. Progress Florida is requesting an effective date of December 18, 2002 for this Rate Schedule.

Progress Florida states that a copy of the filing was served upon the Florida Public Service Commission and the North Carolina Utilities Commission.

Comment Date: February 7, 2003.

12. Mesquite Power, LLC

[Docket No. ER03–427–000]

Take notice that on January 17, 2003, Mesquite Power, LLC (Mesquite) tendered for filing pursuant to Rule 205, 18 CFR 385.205, a petition for waivers and blanket approvals under various regulations of the Commission and for an order accepting its FERC Electric Tariff No. 1.

Mesquite intends to sell electric power and ancillary services at wholesale rates, terms, and conditions to be mutually agreed to with the purchasing party. The Mesquite tariff provides for the sale of electric energy, capacity and ancillary services at agreed prices.

Comment Date: February 7, 2003.

13. ConocoPhillips Company

[Docket No. ER03–428–000]

Take notice that on January 17, 2003, ConocoPhillips Company (ConocoPhillips) tendered for filing a Notice of Succession pursuant to Section 35.16 of the Commission's Regulations. As a result of a name change, ConocoPhillips is succeeding by merger to the tariffs and related service agreements of Conoco Inc., effective December 31, 2002.

Comment Date: February 7, 2003.

14. Sierra Pacific Power Company

[Docket No. ER03–429–000]

Take notice that on January 17, 2003, Sierra Pacific Power Company (Sierra Pacific), submitted for filing a Power Purchase Agreement (PPA) between Sierra Pacific and Nevada Power Company, pursuant to Section 205'' of the Federal Power Act, 16 U.S.C. 824d'' and Section 35.12 of the Commission's rules and regulations, 18 CFR 35.12. Sierra Pacific Power requests an effective date of March 1, 2003 for the PPA.

Comment Date: February 7, 2003.

15. Nevada Power Company

[Docket No. ER03–430–000]

Take notice that on January 17, 2003, Nevada Power Company (Nevada Power), submitted for filing five Power Purchase Agreements (PPAs) between Nevada Power and Sierra Pacific Power Company, pursuant to Section 205'' of the Federal Power Act, 16 U.S.C.824d'', and Section 35.12 the Commission's rules and regulations, 18 CFR 35.12. Nevada Power requests an effective date of March 1, 2003 for the PPAs.

Comment Date: February 7, 2003.

16. Dynegy, Inc.

[Docket No. ES03–20–000]

Take notice that on January 13, 2003, Dynegy, Inc. submitted an application requesting a blanket authorization under section 204 of the Federal Power Act and part 34 of the Commission's regulations.

Comment Date: February 3, 2003.

Standard Paragraph

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). 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. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's Web site at *http://www.ferc.gov* , using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number filed to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866)208–3676, or for TTY, contact (202)502–8659. Protests and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The

Commission strongly encourages electronic filings.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1925 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER97–1523–072, et al.]

New York Independent System Operator, Inc., et al.; Electric Rate and Corporate Filings

January 21, 2003.

The following filings have been made with the Commission. The filings are listed in ascending order within each docket classification.

1. New York Independent System Operator, Inc.

[Docket Nos. ER97–1523–072, OA97–470–067, and ER97–4234–065]

Take notice that on January 16, 2003, the New York Independent System Operator, Inc. (NYISO), tendered for filing a refund report, in connection with the Commission's November 1, 2002, Order in the above-referenced dockets.

The NYISO has served a copy of this filing to all parties listed on the official service list maintained by the Secretary of the Commission in docket numbers ER97–1523–063, OA97–470–058 and ER97–4234–056.

Comment Date: February 6, 2003.

2. Southern California Edison Company

[Docket No. ER02–925–003]

Take notice that on January 17, 2003, Southern California Edison Company (SCE) tendered for filing revised rate sheets for its Transmission Owner Tariff (TO Tariff), FERC Electric Tariff, First Revised Volume No. 6. The purpose of this filing is to comply with the Federal Energy Regulatory Commission's letter order rendered in Docket No. ER02–925 on December 24, 2002.

SCE states that copies of this filing were served upon the Service List compiled by the Secretary in this docket.

Comment Date: February 7, 2003.

3. Boston Edison Company

[Docket No. ER03–161–001]

Take notice that on January 17, 2003, Boston Edison Company (Boston Edison) tendered for filing an executed Related Facilities Agreement between Boston Edison and Lake Road Generating Company, L.P., in compliance with the directives of the Commission as stated in its December 19, 2002 letter order in Docket No. ER03–161–000.

Boston Edison requests an effective date of the Agreement of January 5, 2003.

Comment Date: February 7, 2003.

4. San Diego Gas & Electric Company

[Docket Nos. ER03–418–000 and ER99–3426–003]

Take notice that on January 15, 2003, San Diego Gas & Electric Company (SDG&E) tendered for filing with the Federal Energy Regulatory Commission (Commission) revised tariff sheets and a request for continued authorization by the Commission for SDG&E to make wholesale power sales at market-based rates. SDG&E requests that the Commission grant certain waivers and accept for filing a proposed tariff governing sales of electric capacity, energy and certain ancillary services at market-based rates in the Western Interconnection pursuant to Section 205 of the Federal Power Act.

Comment Date: February 5, 2003.

5. Wayne-White Counties Electric Cooperative

[Docket No. ER03–419–000]

Take notice that on January 15, 2003, Wayne-White Counties Electric Cooperative (Wayne-White or Cooperative), tendered for filing an executed Service Agreement for Firm Point-to-Point Transmission Service with Illinois Power Company. Under the Service Agreement, Wayne-White will provide firm point-to-point transmission service to Illinois Power Company under the Cooperative's Open Access Transmission Tariff. Wayne-White requests an effective date of January 1, 2003, the date service was first provided.

Wayne-White states that a copy of the filing was served upon Illinois Power Company.

Comment Date: February 5, 2003.

6. PPL Wallingford Energy LLC and PPL EnergyPlus, LLC

[Docket No. ER03–421–000

Take notice that on January 16, 2003, PPL Wallingford Energy LLC (PPL Wallingford) and PPL EnergyPlus, LLC (PPL EnergyPlus) filed a Cost of Service Agreement among PPL Wallingford, PPL EnergyPlus and ISO New England Inc. (ISO-NE) in the above-captioned proceeding. PPL Wallingford and PPL EnergyPlus request an effective date of February 1, 2003 and request waivers of all applicable Commission regulations to permit such effective date.

PPL Wallingford and PPL EnergyPlus have provided a copy of this filing to ISO-NE on the date of filing and have also provided courtesy copies to the utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont and to Counsel to the NEPOOL Participants Committee.

Comment Date: February 6, 2003.

7. Safe Harbor Water Power Corporation

[Docket No. ER03–423–000]

Take notice that on January 16, 2003, Safe Harbor Water Power Corporation (Safe Harbor) tendered for filing, under section 205 of the Federal Power Act, a rate schedule for reactive power and voltage control from generation sources service provided to the transmission facilities controlled by the PJM Interconnection LLC (PJM). Safe Harbor respectfully requests that the Commission accept the proposed rate schedule for filing on or before February 28, 2003 in order to permit the rate schedule to become effective on March 1, 2003, thereby alleviating the need for any retroactive billing by PJM.

Safe Harbor states that they mailed a copy of this filing to PJM.

Comment Date: February 6, 2003.

8. Virginia Electric and Power Company

[Docket No. ER03–426–000]

Take notice that on January 17, 2003, Virginia Electric and Power Company (Dominion Virginia Power or the Company) tendered for filing a Service Agreement for Network Integration Transmission Service and Network Operating Agreement by Dominion Virginia Power to the Town of Enfield, NC, designated as Service Agreement Number 372, under the Company's Open Access Transmission Tariff, FERC Electric Tariff, Second Revised Volume No. 5, to Eligible Purchasers dated June 7, 2000.

Dominion Virginia Power requests an effective date of January 1, 2003, the date service was first provided to the customer. *Comment Date:* February 7, 2003.

Standard Paragraph

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). 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. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's Web site at *http://www.ferc.gov*, using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number filed to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866)208–3676, or for TTY, contact (202)502–8659. Protests and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1926 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Application for Amendment of License and Soliciting Comments, Motions To Intervene, and Protests

January 22, 2003.

Take notice that the following application has been filed with the Commission and is available for public inspection:

a. *Application Type*: Amendment of License.

b. *Project No.*: 1005–010.

c. *Date Filed:* August 1, 2002, October 28, 2002, and October 29, 2002.

d. *Applicant:* City of Boulder, Colorado.

e. *Name of Project:* Boulder Canyon.

f. *Location:* The project is located on the Middle Boulder Creek in Boulder County, Colorado.

g. *Filed Pursuant to*: Federal Power Act, 18 CFR 4.38(a)(v).

h. *Applicant Contact:* Carol D. Ellinghouse, P.E., City of Boulder, Public Works Department-Utilities Division, 1739 Broadway, Boulder, CO 80306.

i. *FERC Contact:* Any questions on this notice should be addressed to Mr. Eric Gross at (202) 502–6213, or e-mail address: *eric.gross@ferv.gov*.

j. *Deadline for filing comments and or motions*: February 18, 2003.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington DC 20426. Please include the project number (P–1005–010) on any comments or motions filed.

k. *Description of Request:* The City of Boulder proposes the construction of new outlet works at the Barker Dam. The City states that the new outlet works would not affect project operation or capacity.

l. *Locations of the Application:* A copy of the application is available for inspection and reproduction at the Commission's Public Reference Room, located at 888 First Street, NE., Room 2A, Washington, DC 20426, or by calling (202) 502–8371. This filing may also be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link.

Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, call 1–866–208–3676 or e-mail *FERCOnlineSupport@ferc.gov*. For TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at the address in item (h) above.

m. Individuals desiring to be included on the Commission's mailing list should so indicate by writing to the Secretary of the Commission.

n. 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.

o. Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''RECOMMENDATIONS FOR TERMS AND CONDITIONS'', ''PROTEST'', OR ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. A copy of any motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

p. 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.

q. Comments, protests and interventions may be filed electronically via the Internet in lieu of paper. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site at *http://www.ferc.gov* under the ''e-Filing'' link.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1928 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Application for Amendment of License and Soliciting Comments, Motions To Intervene, and Protests

January 22, 2003.

Take notice that the following application has been filed with the Commission and is available for public inspection:

a. *Application Type*: Amendment of License to Change Project Design and Project Boundary Due to Proposed Relocation of Powerhouse.

b. *Project No.*: 11175–016.

c. *Date Filed:* April 4, 2002.

d. *Applicant:* Crown Hydro, LLC.

e. *Name of Project:* Crown Mill.

f. *Location:* The project is located on the Mississippi River, in Hennepin County, Minnesota.

g. *Filed Pursuant to*: Federal Power Act, 16 U.S.C. 791 (a) 825(r) and 799 and 801.

h. *Applicant Contact:* Tom Griffin, Crown Hydro LLC, 5436 Columbus Avenue South, Minneapolis, MN 55427, (612) 825–1043.

i. *FERC Contact:* Any questions on this notice should be addressed to Mrs. Anumzziatta Purchiaroni at (202) 502–6191, or e-mail address: *anumzziatta.purchiaroni@ferc.gov*.

j. *Deadline for filing comments and or motions:* February 18, 2003.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington DC 20426. Please include the project number (P–

11175–016) on any comments or motions filed.

k. *Description of Request:* Crown Hydro LLC (Crown) is proposing a change in project boundary to relocate the project's powerhouse, and to make additional modifications to the project. The project as originally licensed in 1999 included a powerhouse containing two vertical Kaplan generating units with a total capacity of 3,400 kW to be located in the basement of the historic Crown Roller Building on the west side of West River Parkway. Crown is now proposing to construct a powerhouse containing two vertical Kaplan generating units with a total capacity of 3,150 kW, on the east side of the West River Parkway, within the footprint of the remains of the Holly and Cataract Mill Foundation. The relocated powerhouse would be designed as an at-grade structure with two stairwells that would have above ground fencing, located within the Minneapolis Park and Recreation Board's property, at the Mill Ruins Park. Resources affected by this proposed amendment include cultural and aquatics.

l. *Locations of the Application:* A copy of the application is available for inspection and reproduction at the Commission's Public Reference Room, located at 888 First Street, NE., Room 2A, Washington, DC 20426, or by calling (202) 502–8371. This filing may also be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, call 1–866–208–3676 with or e-mail *FERCOnlineSupport@ferc.gov*. For TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at the address in item (h) above.

m. Individuals desiring to be included on the Commission's mailing list should so indicate by writing to the Secretary of the Commission.

n. 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.

o. Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''RECOMMENDATIONS FOR TERMS AND CONDITIONS'', ''PROTEST'', OR ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. A copy of any motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

p. 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.

q. Comments, protests and interventions may be filed electronically via the Internet in lieu of paper. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site at *http://www.ferc.gov* under the ''e-Filing'' link.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1929 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12301–000]

Notice of Application Accepted for Filing and Soliciting Motions To Intervene, Protests, and Comments

January 22, 2003.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Type of Application:* Preliminary Permit.

b. *Project No.:* 12301–000.

c. *Date filed:* July 5, 2001.

d. *Applicant:* Point Marion Hydro, LLC.

e. *Name of Project:* Point Marion Lock Dam Project.

f. *Location:* On the Monongahela River, in Fayette County, Pennsylvania. Utilizing the U.S. Army Corps of Engineers' existing Point Marion Lock and Dam.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791(a)—825(r).

h. *Applicant Contact:* Mr. Brent L. Smith, President, Northwest Power Services, Inc., P.O. Box 535, Rigby, ID 83442, (208)745–0834.

i. *FERC Contact:* Robert Bell, (202) 219–2806.

j. *Deadline for filing motions to intervene, protests and comments*: 60 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Comments, protests, and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings. Please include the project number (P–12301–000) on any comments or motions filed.

The Commission's Rules of Practice and Procedure require all interveners filing documents with the Commission to serve a copy of that document on each person in the official service list for the project. Further, if an intervener files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

k. *Competing Application Project No.:* 12269–000, *Date Filed:* June 25, 2002, *Date Notice Closed:* October 22, 2002.

1. *Description of Project:* The proposed project using the U.S. Army Corps of Engineer's Point Marion Lock and Dam and impoundment would consist of: (1) A proposed 50-foot-long, 168-inch diameter concrete penstock, (2) a proposed powerhouse containing one generating unit having an installed capacity of 3.2 MW, (3) a proposed 1-mile-long, 25 kV transmission, and (4) appurtenant facilities.

The project would have an annual generation of 18 GWh that would be sold to a local utility. m. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, call toll-free 1–866–208–3676 or e-mail ferconlinesupport@ferc.gov. For TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at Point Marion Hydro, LLC, 975 South State Highway, Logan, UT 84321, (435) 752–2580.

n. Competing Applications—Public notice of the filing of the initial

preliminary permit application, which has already been given, established the due date for filing competing preliminary permit applications or notices of intent. Any competing preliminary permit or development application or notice of intent to file a competing preliminary permit or development application must be filed in response to and in compliance with the public notice of the initial preliminary permit application. No competing applications or notices of intent to file competing applications may be filed in response to this notice. A competing license application must conform with 18 CFR 4.30 (b) and 4.36.

o. Proposed Scope of Studies under Permit—A preliminary permit, if issued, does not authorize construction. The term of the proposed preliminary permit would be 36 months. The work proposed under the preliminary permit would include economic analysis, preparation of preliminary engineering plans, and a study of environmental impacts. Based on the results of these studies, the Applicant would decide whether to proceed with the preparation of a development application to construct and operate the project.

p. 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.

q. Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''NOTICE OF INTENT TO FILE COMPETING APPLICATION'', ''COMPETING APPLICATION'', ''PROTEST'', ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. Any of the above-named 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, NE., Washington, DC 20426. An additional copy must be sent to Director, Division of Hydropower Administration and Compliance, Federal Energy Regulatory Commission, at the above-mentioned address. A copy of any notice of intent, competing application or motion to intervene must also be served upon each representative of the Applicant specified in the particular application..

r. 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.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1930 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12306–000]

Notice of Application Accepted for Filing and Soliciting Motions To Intervene, Protests, and Comments

January 22, 2003.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Type of Application:* Preliminary Permit.

b. *Project No.:* 12306–000.

c. *Date filed:* July 15, 2002.

d. *Applicant:* Universal Electric Power.

e. *Name of Project:* Mahoning Creek Dam Project.

f. *Location:* On Mahoning Creek, in Armstrong County, Pennsylvania, utilizing the U.S. Army Corps of Engineers Mahoning Creek Dam.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791(a)—825(r).

h. *Applicant Contact:* Mr. Raymond Helter, Universal Electric Power Corp., 1145 Highbrook Street, Akron, OH 44301, (330) 535–7115.

i. *FERC Contact:* Robert Bell, (202) 502–6062.

j. *Deadline for filing comments, protests, and motions to intervene:* 60 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Comments, protests, and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings. Please include the project number (P–12306–000) on any comments or motions filed.

The Commission's Rules of Practice and Procedure require all interveners filing documents with the Commission to serve a copy of that document on each person in the official service list for the project. Further, if an intervener files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

k. *Description of Project:* The proposed project would utilize the Corps' existing Mahoning Creek Dam and consist of: (1) two proposed 35-foot-long, 58-inch diameter steel penstocks, (2) a proposed powerhouse containing two generating units having a total installed capacity of 1.4 MW, (3) a proposed 1500-foot-long, 14.7 kV transmission line, and (4) appurtenant facilities.

Applicant estimates that the average annual generation would be 9 GWh and would be sold to a local utility.

1. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, call toll-free 1–866–208–3676 or e-mail ferconlinesupport@ferc.gov. For TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

m. Competing Preliminary Permit—Anyone desiring to file a competing application for preliminary permit for a proposed project must submit the competing application itself, or a notice of intent to file such an application, to the Commission on or before the specified comment date for the particular application (*see* 18 CFR 4.36). Submission of a timely notice of intent allows an interested person to file the competing preliminary permit application no later than 30 days after the specified comment date for the particular application. A competing preliminary permit application must conform with 18 CFR 4.30(b) and 4.36.

n. Competing Development Application—Any qualified development applicant desiring to file a

competing development application must submit to the Commission, on or before a specified comment date for the particular application, either a competing development application or a notice of intent to file such an application. Submission of a timely notice of intent to file a development application allows an interested person to file the competing application no later than 120 days after the specified comment date for the particular application. A competing license application must conform with 18 CFR 4.30(b) and 4.36.

o. Notice of Intent—A notice of intent must specify the exact name, business address, and telephone number of the prospective applicant, and must include an unequivocal statement of intent to submit, if such an application may be filed, either a preliminary permit application or a development application (specify which type of application). A notice of intent must be served on the applicant(s) named in this public notice.

p. Proposed Scope of Studies under Permit—A preliminary permit, if issued, does not authorize construction. The term of the proposed preliminary permit would be 36 months. The work proposed under the preliminary permit would include economic analysis, preparation of preliminary engineering plans, and a study of environmental impacts. Based on the results of these studies, the Applicant would decide whether to proceed with the preparation of a development application to construct and operate the project.

q. 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.

r. Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''NOTICE OF INTENT TO FILE COMPETING APPLICATION'', ''COMPETING APPLICATION'', ''PROTEST'', ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. Any of the above-named 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, NE., Washington, DC 20426. An additional copy must be sent to Director, Division of Hydropower Administration and Compliance, Federal Energy Regulatory Commission, at the above-mentioned address. A copy of any notice of intent, competing application or motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

s. 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.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1931 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12310–000]

Notice of Application Accepted for Filing and Soliciting Motions to Intervene, Protests, and Comments

January 22, 2003.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Type of Application:* Preliminary Permit.

b. *Project No.:* 12310–000.

c. *Date filed:* July 17, 2002.

d. *Applicant:* Universal Electric Power Corp.

e. *Name of Project:* Sutton Dam Project.

f. *Location:* On the Elk River and Sutton Lake, in Braxton County, West Virginia, utilizing the U.S. Army Corps of Engineers Sutton Dam.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791(a)—825(r).

h. *Applicant Contact:* Mr. Raymond Helter, Universal Electric Power Corp., 1145 Highbrook Street, Akron, OH 44301, (330) 535–7115.

i. *FERC Contact:* Robert Bell, (202) 502–6062.

j. *Deadline for filing comments, protests, and motions to intervene:* 60 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Comments, protests, and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings. Please include the project number (P–12310–000) on any comments or motions filed. The Commission's Rules of Practice and Procedure require all interveners filing documents with the Commission to serve a copy of that document on each person in the official service list for the project. Further, if an intervener files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

k. *Description of Project:* The proposed project would utilize the Corps' existing Sutton Dam and consist of: (1) five proposed 50-foot-long, 54-inch diameter steel penstocks, (2) a proposed powerhouse containing five generating units having a total installed capacity of 3.7 MW, (3) a proposed 1200-foot-long, 14.7 kV transmission line, and (4) appurtenant facilities.

Applicant estimates that the average annual generation would be 24 GWh and would be sold to a local utility.

l. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, call toll-free 1–866–208–3676 or e-mail *ferconlinesupport@ferc.gov*. For TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

m. Competing Preliminary Permit—Anyone desiring to file a competing application for preliminary permit for a proposed project must submit the competing application itself, or a notice of intent to file such an application, to the Commission on or before the specified comment date for the particular application (*see* 18 CFR 4.36). Submission of a timely notice of intent allows an interested person to file the competing preliminary permit application no later than 30 days after

the specified comment date for the particular application. A competing preliminary permit application must conform with 18 CFR 4.30(b) and 4.36.

n. Competing Development Application—Any qualified development applicant desiring to file a competing development application must submit to the Commission, on or before a specified comment date for the particular application, either a competing development application or a notice of intent to file such an application. Submission of a timely notice of intent to file a development application allows an interested person to file the competing application no later than 120 days after the specified comment date for the particular application. A competing license application must conform with 18 CFR 4.30(b) and 4.36.

o. Notice of Intent—A notice of intent must specify the exact name, business address, and telephone number of the prospective applicant, and must include an unequivocal statement of intent to submit, if such an application may be filed, either a preliminary permit application or a development application (specify which type of application). A notice of intent must be served on the applicant(s) named in this public notice.

p. Proposed Scope of Studies under Permit—A preliminary permit, if issued, does not authorize construction. The term of the proposed preliminary permit would be 36 months. The work proposed under the preliminary permit would include economic analysis, preparation of preliminary engineering plans, and a study of environmental impacts. Based on the results of these studies, the Applicant would decide whether to proceed with the preparation of a development application to construct and operate the project.

q. 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.

r. Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''NOTICE OF INTENT TO FILE COMPETING APPLICATION'', ''COMPETING APPLICATION'', ''PROTEST'', ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. Any of the above-named 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, NE., Washington, DC 20426. An additional copy must be sent to Director, Division of Hydropower Administration and Compliance, Federal Energy Regulatory Commission, at the above-mentioned address. A copy of any notice of intent, competing application or motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

s. 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.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1932 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12381–000]

Notice of Application Accepted for Filing and Soliciting Motions to Intervene, Protests, and Comments

January 22, 2003.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Type of Application:* Preliminary Permit.

b. *Project No.:* 12381–000.

c. *Date filed:* October 1, 2002.

d. *Applicant:* Nelson Hydroelectric LLC.

e. *Name of Project:* Red River Lock and Dam #1 Project.

f. *Location:* On the Red River, in Rapides County, Louisiana, utilizing the U.S. Army Corps of Engineers Red River Lock and Dam #1.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791(a)—825(r).

h. *Applicant Contact:* Nelson Hydroelectric LLC: Mr. Robert Larson, Gray, Plant, Mooty, Mooty, & Bennett, 33 South Sixth Street, Minneapolis, MN 55402, (612) 343–2913.

i. *FERC Contact:* Robert Bell, (202) 502–6062.

j. *Deadline for filing comments, protests, and motions to intervene:* 60 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Comments, protests, and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings. Please include the project number (P–12381–000) on any comments or motions filed.

The Commission's Rules of Practice and Procedure require all interveners filing documents with the Commission to serve a copy of that document on each person in the official service list for the project. Further, if an intervener files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

k. *Description of Project:* The proposed project would utilize the Corp's existing Red River Lock and Dam #1 and consist of: (1) eight proposed 80-foot-long, 114-inch diameter steel penstock, (2) a proposed powerhouse containing eight generating units having an installed capacity of 16.2 MW, (3) a proposed 500-foot-long, 14.7 kV transmission line, and (4) appurtenant facilities.

Applicant estimates that the average annual generation would be 9.9 GWh and would be sold to a local utility.

l. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, call toll-free 1–866–208–3676 or e-mail *ferconlinesupport@ferc.gov*. For TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

m. Competing Preliminary Permit—Anyone desiring to file a competing

application for preliminary permit for a proposed project must submit the competing application itself, or a notice of intent to file such an application, to the Commission on or before the specified comment date for the particular application (*see* 18 CFR 4.36). Submission of a timely notice of intent allows an interested person to file the competing preliminary permit application no later than 30 days after the specified comment date for the particular application. A competing preliminary permit application must conform with 18 CFR 4.30(b) and 4.36.

n. Competing Development Application—Any qualified development applicant desiring to file a competing development application must submit to the Commission, on or before a specified comment date for the particular application, either a competing development application or a notice of intent to file such an application. Submission of a timely notice of intent to file a development application allows an interested person to file the competing application no later than 120 days after the specified comment date for the particular application. A competing license application must conform with 18 CFR 4.30(b) and 4.36.

o. Notice of Intent—A notice of intent must specify the exact name, business address, and telephone number of the prospective applicant, and must include an unequivocal statement of intent to submit, if such an application may be filed, either a preliminary permit application or a development application (specify which type of application). A notice of intent must be served on the applicant(s) named in this public notice.

p. Proposed Scope of Studies under Permit—A preliminary permit, if issued, does not authorize construction. The term of the proposed preliminary permit would be 36 months. The work proposed under the preliminary permit would include economic analysis, preparation of preliminary engineering plans, and a study of environmental impacts. Based on the results of these studies, the Applicant would decide whether to proceed with the preparation of a development application to construct and operate the project.

q. 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.

r. Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''NOTICE OF INTENT TO FILE COMPETING APPLICATION'', ''COMPETING APPLICATION'', ''PROTEST'', ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. Any of the above-named 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, NE., Washington, DC 20426. An additional copy must be sent to Director, Division of Hydropower Administration and Compliance, Federal Energy Regulatory Commission, at the above-mentioned address. A copy of any notice of intent, competing application or motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

s. 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.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1933 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 12402–000]

Notice of Application Accepted for Filing and Soliciting Motions to Intervene, Protests, and Comments

January 22, 2003.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Type of Application:* Preliminary Permit.

b. *Project No.:* 12402–000.

c. *Date filed*: October 30, 2002.

d. *Applicant:* Universal Electric Power Corp.

e. *Name of Project:* Mississippi Lock and Dam #10 Project.

f. *Location:* On the Mississippi River, in Clayton County, Iowa, utilizing the U.S. Army Corps of Engineers Mississippi Lock and Dam #10.

g. *Filed Pursuant to*: Federal Power Act, 16 U.S.C. 791(a)—825(r).

h. *Applicant Contact:* Mr. Raymond Helter, Universal Electric Power Corp., 1145 Highbrook Street, Akron, OH 44301, (330) 535–7115.

i. *FERC Contact:* Robert Bell, (202) 502–6062.

j. *Deadline for filing comments, protests, and motions to intervene*: 60 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Comments, protests, and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings. Please include the project number (P–12402–000) on any comments or motions filed.

The Commission's Rules of Practice and Procedure require all interveners filing documents with the Commission to serve a copy of that document on each person in the official service list for the project. Further, if an intervener files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

k. *Description of Project*: The proposed project would utilize the Corps' existing Mississippi Lock and Dam #10 and consist of: (1) five proposed 80-foot-long, 114-inch-diameter steel penstocks, (2) a proposed powerhouse containing five generating units having an installed capacity of 100 MW, (3) a proposed 200-foot-long, 14.7 kV transmission line, and (4) appurtenant facilities.

Applicant estimates that the average annual generation would be 61 GWh and would be sold to a local utility.

l. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number

field to access the document. For assistance, call toll-free 1–866–208–3676 or e-mail ferconlinesupport@ferc.gov. For TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

m. Competing Preliminary Permit—Anyone desiring to file a competing application for preliminary permit for a proposed project must submit the competing application itself, or a notice of intent to file such an application, to the Commission on or before the specified comment date for the particular application (*see* 18 CFR 4.36). Submission of a timely notice of intent allows an interested person to file the competing preliminary permit application no later than 30 days after the specified comment date for the particular application. A competing preliminary permit application must conform with 18 CFR 4.30(b) and 4.36.

n. Competing Development Application—Any qualified development applicant desiring to file a competing development application must submit to the Commission, on or before a specified comment date for the particular application, either a competing development application or a notice of intent to file such an application. Submission of a timely notice of intent to file a development application allows an interested person to file the competing application no later than 120 days after the specified comment date for the particular application. A competing license application must conform with 18 CFR 4.30(b) and 4.36.

o. Notice of Intent—A notice of intent must specify the exact name, business address, and telephone number of the prospective applicant, and must include an unequivocal statement of intent to submit, if such an application may be filed, either a preliminary permit application or a development application (specify which type of application). A notice of intent must be served on the applicant(s) named in this public notice.

p. Proposed Scope of Studies under Permit—A preliminary permit, if issued, does not authorize construction. The term of the proposed preliminary permit would be 36 months. The work proposed under the preliminary permit would include economic analysis, preparation of preliminary engineering plans, and a study of environmental impacts. Based on the results of these studies, the Applicant would decide whether to proceed with the preparation of a development application to construct and operate the project.

q. 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.

r. Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''NOTICE OF INTENT TO FILE COMPETING APPLICATION'', ''COMPETING APPLICATION'', ''PROTEST'', ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. Any of the above-named 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, NE., Washington, DC 20426. An additional copy must be sent to Director, Division of Hydropower Administration and Compliance, Federal Energy Regulatory Commission, at the above-mentioned address. A copy of any notice of intent, competing application or motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

s. 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.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1934 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Application Accepted for Filing and Soliciting Motions to Intervene and Protests

January 22, 2003.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection.

a. *Type of Application:* Minor original license.

b. *Project No.:* 12423–000.

c. *Date filed*: November 25, 2002.

d. *Applicant:* American Falls Reservoir District No. 2 and Big Wood Canal Company.

e. *Name of Project:* 993 Hydroelectric Project.

f. *Location:* Juncture of the 993 Lateral and North Gooding Main Canal, Boise Meridian, 20 miles northwest of the Town of Shoshone, Lincoln County, Idaho. The initial diversion is the Milner Dam on the Snake River. The North Gooding Main Canal is part of a U.S. Bureau of Reclamation (Bureau) project. The project would occupy about 10–15 acres of Federal land managed by the Bureau.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791 (a)—825'').

h. *Applicant Contact:* Lynn Harmon, General Manager, American Falls Reservoir District No. 2 and Big Wood Canal Company, Box C, Shoshone, Idaho, 83352; (208) 886–2331.

i. *FERC Contact:* Allison Arnold, (202) 502–6346 or *allison.arnold@ferc.gov*.

j. *Deadline for filing motions to intervene and protests:* 60 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

The Commission's Rules of Practice require all intervenors filing documents with the Commission to serve a copy of that document on each person on the official service list for the project. Further, if an intervenor files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

Motions to intervene and protests may be filed electronically via the Internet in lieu of paper. The Commission strongly encourages electronic filings.*See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://*

www.ferc.gov) under the ''e-Filing'' link.

k. This application has been accepted for filing, but is not ready for environmental analysis at this time.

l. The 993 Hydroelectric Power Project would consist of: (1) a new concrete diversion structure located across the North Gooding Main Canal with a maximum height of 10 feet; (2) a new 7,000-foot-long canal with a bottom width of 25 feet that is to be excavated from rock, with some earth embankment, having a hydraulic capacity of 350 cfs; (3) a 10-foot-high gated concrete diversion structure that would divert up to 350 cfs to a concrete intake structure; (4) a 2,900-foot-long steel pipe (or HDPE) penstock (72 inch diameter); (5) a 30 by 50-foot concrete with masonry or metal walled powerhouse containing two 750-kilowatt (kW) turbines with a total installed capacity of 1,500 kW; (6) an enlarged 100-foot-long tailrace channel with a bottom width of 40 feet that would discharge into the North Gooding Main Canal; (7) a 2.4-mile-long transmission line, and (8) appurtenant facilities. The annual generation would be approximately 5.8 gigawatt-hours.

m. A copy of the application is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at 1–866–208–3676, or for TTY, (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

n. Any qualified applicant desiring to file a competing application must submit to the Commission, on or before the specified deadline date for the particular application, a competing development application, or a notice of intent to file such an application.

Submission of a timely notice of intent allows an interested person to file the competing development application no later than 120 days after the specified deadline date for the particular application. Applications for preliminary permits will not be accepted in response to this notice.

A notice of intent must specify the exact name, business address, and telephone number of the prospective applicant, and must include an unequivocal statement of intent to submit, if such an application may be filed, either a preliminary permit application or a development application (specify which type of application). A notice of intent must be served on the applicant(s) named in this public notice.

Anyone may submit a protest or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, 385.211, and 385.214. In determining the appropriate action to take, the Commission will consider all protests 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 protests or motions to intervene must be received on or before the specified deadline date for the particular application.

When the application is ready for environmental analysis, the Commission will issue a public notice requesting comments, recommendations, terms and conditions, or prescriptions.

All filings must (1) bear in all capital letters the title ''PROTEST'' or ''MOTION TO INTERVENE,'' ''NOTICE OF INTENT TO FILE COMPETING APPLICATION,'' or ''COMPETING APPLICATION;'' (2) set forth in the heading the name of the applicant and the project number of the application to which the filing responds; (3) furnish the name, address, and telephone number of the person protesting or intervening; and (4) otherwise comply with the requirements of 18 CFR 385.2001 through 385.2005. Agencies may obtain copies of the application directly from the applicant. A copy of any protest or motion to intervene must be served upon each representative of the applicant specified in the particular application.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1935 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Application Accepted for Filing and Soliciting Motions to Intervene and Protest

January 22, 2003.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection.

a. *Type of Application:* New Minor License.

b. *Project No.:* 1273–009.

c. *Date Filed:* November 15, 2002.

d. *Applicant:* Parowan City.

e. *Name of Project:* Center Creek Hydroelectric Project.

f. *Location:* At the confluence of Center Creek (aka Parowan Creek) and Bowery Creek (a tributary to Parowan Creek) near the City of Parowan, in Iron County, Utah. The project occupies 21.43 acres of land managed by the U.S. Department of the Interior, Bureau of Land Management.

g. *Filed Pursuant to:* Federal Power Act 16 U.S.C. 791 (a)–825(r).

h. *Applicant Contact:* Alden C. Robinson, P.E., Sunrise Engineering, Inc., 25 East 500 North, Fillmore, Utah 84631, (435) 743–6151 and/or Clark Gates II, City Manager, Parowan City, P.O. Box 576, Parowan, Utah 84761, (435) 477–3331.

i. *FERC Contact:* Gaylord Hoisington, (202) 502–8163, *gaylord.hoisington@FERC.gov*.

j. *Cooperating agencies*: We are asking Federal, state, local, and tribal agencies with jurisdiction and/or special expertise with respect to environmental issues to cooperate with us in the preparation of the environmental document. Agencies who would like to request cooperating status should follow the instructions for filing comments described in item k below.

k. *Deadline for filing motions to intervene and protests and requests for cooperating agency status*: 60 days from the issuance date of this notice.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

The Commission's Rules of Practice require all intervenors filing documents with the Commission to serve a copy of that document on each person on the official service list for the project. Further, if an intervenor files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

Motions to intervene and protests and requests for cooperating agency status may be filed electronically via the Internet in lieu of paper. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://www.ferc.gov*) under the ''e-Filing'' link.

l. This application has been accepted, but is not ready for environmental analysis at this time.

m. The existing Center Creek Hydroelectric Project consists of: (1) a 15-foot-high, 54-foot-long concrete overflow type diversion dam; (2) a

radial gate; (3) trash racks; (4) a 19.9 acre-foot de-silting pond; (5) an 18 to 26-inch-diameter, 18,825-foot-long steel penstock; (5) a 600-kilowatt powerhouse; and (6) appurtenant facilities.

n. A copy of the application is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676 or for TTY, (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

o. Anyone may submit a protest or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, 385.211, and 385.214. In determining the appropriate action to take, the Commission will consider all protests 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 protests or motions to intervene must be received on or before the specified deadline date for the particular application.

All filings must (1) bear in all capital letters the title ''PROTEST'' or ''MOTION TO INTERVENE;'' (2) set forth in the heading the name of the applicant and the project number of the application to which the filing responds; (3) furnish the name, address, and telephone number of the person protesting or intervening; and (4) otherwise comply with the requirements of 18 CFR 385.2001 through 385.2005. Agencies may obtain copies of the application directly from the applicant. A copy of any protest or motion to intervene must be served upon each representative of the applicant specified in the particular application.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1936 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Intent to Prepare Environmental Assessment, Availability of Scoping Document, and Soliciting Scoping Comments

January 22, 2003.

Take notice that the following hydroelectric application has been filed with Commission and are available for public inspection:

a. *Type of Application:* New Minor License.

b. *Project No.:* 7725–005.

c. *Date filed:* September 27, 2002.

d. *Applicant:* Barton Village Inc.

e. *Name of Project:* Barton Village Hydroelectric Project.

f. *Location:* On the Clyde River in the Town of Charleston, Vermont. No federal lands are affected.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791(a)—825(r).

h. *Applicant Contact:* Denis H. Poirier, Village Supervisor, Barton Village, Inc. 17 Village Square, P.O. Box 519, Barton, Vermont 05822. (802)525–4747.

i. *FERC Contact:* Frank Winchell at (202)502–6104 or *frank.winchell@ferc.gov*.

j. *Deadline for filing scoping comments:* 30 days from the date of this notice.

All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Comments, protests and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings.

The Commission's Rules of Practice and Procedure require all interveners filing documents with the Commission to serve a copy of that document on each person on the official service list for the project. Further, if an intervener files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

Scoping comments may be filed electronically via the Internet in lieu of paper. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://www.ferc.gov*) under the ''FERRIS'' link.

k. This application is not ready for environmental analysis at this time.

l. The existing Barton Village Hydroelectric Project consists of: (1) a 77-foot-long, 24-foot-high masonry and concrete gravity dam; (2) 1.5-foot-high flashboards extending 57 feet across a concrete spillway; (3) a 187-acre impoundment at elevation 1,140.9 feet mean sea level (msl); (4) a 665-foot-long, 7-foot-diameter steel penstock; (5) two 105-foot-long, 5.8-foot-diameter steel penstocks leading to: (6) a powerhouse with two units having a total installed capacity of 1.4 MW; (7) two tailraces; and (8) other appurtenant facilities.

m. A copy of the application is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''FERRIS'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at 1–866–208–3676, or for TTY, (202) 502–8659. A copy is also available for inspection and reproduction at the address in item g above.

n. Scoping Process Pursuant to the National Environmental Policy Act and procedures of the Federal Energy Regulatory Commission (Commission or FERC), the Commission staff intends to prepare an Environmental Assessment (EA) that evaluates the environmental impacts of issuing a new license for the continued operation of the Barton Village Hydroelectric Project, located on the Clyde River in Orleans County, Vermont. The project does not affect Federal lands.

The EA will consider both site-specific and cumulative environmental effects, if any, of the proposed action and reasonable alternatives, and will include an economic, financial, and engineering analysis. Preparation of staff's EA will be supported by a scoping process to ensure identification and analysis of all pertinent issues.

We prepared the enclosed Scoping Document (SD) to provide you with information on:

- the Barton Village Hydroelectric Project;
- the environmental analysis process we will follow to prepare the EA; and
- our preliminary identification of issues that we will address in the EA.

We invite the participation of governmental agencies, non-governmental organizations, and the general public in the scoping process, and have prepared this SD to provide information on the proposed project and to solicit written comments and

suggestions on our preliminary list of issues and alternatives to be addressed in the EA. The SD has been distributed to parties on the Service List for this proceeding and is available from our Public Reference Room at (202)502–8371. It can also be accessed online at *http://www.ferc.gov* under the ''FERRIS'' link.

Given the fact that no comments have been filed related to the relicensing and that Barton Village, Inc. has not proposed any new construction, we do not anticipate at this time that there is adequate justification: (1) to arrange for Commission staff and interested members of the public to visit the project site; or (2) to hold a public meeting near the project site.

Please review this document and, if you wish to provide written input, follow the instructions contained in section 2.2. Please direct any questions about the scoping process to Frank Winchell at (202) 502–6104.

Magalie R. Salas,

Secretary.

[FR Doc. 03–1938 Filed 1–27–03; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Meeting, Notice of Vote, Explanation of Action Closing Meeting and List of Persons to Attend; Sunshine Act

January 22, 2003.

The following notice of meeting is published pursuant to Section 3(a) of the Government in the Sunshine Act (Pub. L. 94–409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING: Federal Energy Regulatory Commission, DOE.

DATE AND TIME: January 29, 2003, (Within a relatively short time before or after the regular Commission Meeting).

PLACE: Hearing Room 6, 888 First Street, NE., Washington, DC 20426.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Non-public investigations and inquiries and enforcement related matters.

CONTACT PERSON FOR MORE INFORMATION: Magalie R. Salas, Secretary, Telephone, (202) 502–8400.

Chairman Wood and Commissioners Massey and Brownell voted to hold a closed meeting on January 29, 2003. The certification of the General Counsel explaining the action closing the meeting is available for public inspection in the Commission's Public Reference Room at 888 First Street, NE., Washington, DC 20426.

The Chairman and the Commissioners, their assistants, the Commission's Secretary and her assistant, the General Counsel and members of her staff, and a stenographer are expected to attend the meeting. Other staff members from the Commission's program offices who will advise the Commissioners in the matters discussed will also be present.

Magalie R. Salas,

Secretary.

[FR Doc. 03–2009 Filed 1–24–03; 11:15 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Sunshine Act Notice

January 22, 2003.

The following notice of meeting is published pursuant to section 3(a) of the Government in the Sunshine Act (Pub. L. 94–409), 5 U.S.C 552B:

AGENCY HOLDING MEETING: Federal Energy Regulatory Commission.

DATE AND TIME: January 29, 2003, 10 a.m.

PLACE: Room 2C, 888 First Street, NE., Washington, DC 20426.

STATUS: Open.

MATTERS TO BE CONSIDERED: Agenda.

Note: items listed on the agenda may be deleted without further notice.

CONTACT PERSON FOR MORE INFORMATION: Magalie R. Salas, Secretary, Telephone, (202) 502–8400. For a recording listing items stricken from or added to the meeting, call (202) 502–8627.

This is a list of matters to be considered by the commission. It does not include a listing of all papers relevant to the items on the agenda; however, all public documents may be examined in the reference and information center.

817th—Meeting January 29, 2003, Regular Meeting, 10 a.m.

Administrative Agenda

A–1.
Docket# AD02–1, 000, Agency Administrative Matters

A–2.
Docket# AD02–7, 000, Customer Matters, Reliability, Security and Market Operations

A–3.
Presentation on Winter Market Assessment

A–4.
Seams Resolution Presentation—RTO West, West Connect, California ISO

Markets, Tariffs and Rates—Electric

E–1.
Docket# EL03–38, 000, Cargill Power Markets, LLC v. Midwest Independent Transmission System Operator, Inc.

E–2.
Docket# EL03–30, 000, Tenaska Power Services Co. v. Midwest Independent Transmission System Operator, Inc.

E–3.
Docket# EL02–101, 001, Cleco Power LLC, Dalton Utilities, Entergy Services, Inc., Georgia Transmission Corporation, JEA, MEAG Power, Sam Rayburn G & T Electric Cooperative, Inc., SouthCarolina Public Service Authority, Southern Company Services, Inc., and the City of Tallahassee, Florida

E–4.
Docket# ER03–265, 000, Midwest Independent Transmission System Operator, Inc.

E–5.
Docket# ER02–1330, 002, Pacific Gas & Electric Company
Other#s EL02–88, 000, Wrightsville Power Facility, L.L.C. v. Entergy Arkansas, Inc.
ER02–1069, 001, Entergy Services, Inc.
ER02–1151, 001, Entergy Services, Inc.
ER02–1472, 001, Entergy Gulf States, Inc.
ER02–2243, 002, Entergy Services, Inc.
EL03–3, 000, Entergy Services, Inc.
EL03–4, 000, Entergy Gulf States, Inc.
EL03–5, 000, Entergy Services, Inc.
EL03–12, 000, Kinder Morgan Michigan, LLC v. Michigan Electric Transmission Company, LLC
EL03–13, 000, Entergy Services Inc.

E–6.
Docket# ER02–199, 000, Mississippi Power Company
Other#s EL02–50, 000, Southern Company Services, Inc.
ER02–218, 000, Southern Company Services, Inc.
ER02–219, 000, Southern Company Services, Inc.
ER02–220, 000, Southern Company Services, Inc.
ER02–221, 000, Southern Company Services, Inc.
ER02–222, 000, Southern Company Services, Inc.
ER02–223, 000, Southern Company Services, Inc.
ER02–224, 000, Southern Company Services, Inc.
ER02–225, 000, Southern Company Services, Inc.
ER02–226, 000, Southern Company Services, Inc.
ER02–227, 000, Georgia Power Company
ER02–228, 000, Georgia Power Company
ER02–229, 000, Alabama Power Company
ER02–230, 000, Alabama Power Company
ER02–498, 000, Gulf Power Company
ER02–788, 000, Gulf Power Company

E–7.
Docket# ER03–210, 000, New England Power Pool

E–8.
Docket# ER03–117, 000, Duke Energy South Bay, LLC

E–9.
Docket# ER03–116, 000, Duke Energy Oakland, LLC

E–10.
Docket# ER03–94, 000, Pacific Gas and Electric Company
E–11.
Docket# ER03–238, 000, New York Independent System Operator, Inc.
E–12.
Omitted
E–13.
Docket# ER03–171, 000, Entergy Services, Inc
Other#s ER03–171, 001, Entergy Services, Inc.
E–14.
Docket# ER03–291, 000, New England Power Company
E–15.
Docket# ER03–304, 000, Consolidated Edison Energy, Inc., and Rockland Electric Company
E–16.
Docket# ER03–106, 000, Virginia Electric and Power Company
Other#s ER03–106, 001, Virginia Electric and Power Company
ER03–106, 002, Virginia Electric and Power Company
E–17.
Omitted
E–18.
Omitted
E–19.
Docket# ER02–64, 000, Mirant Delta, LLC and Mirant Potrero, LLC
Other#s ER02–198, 000, Mirant Delta, LLC and Mirant Potrero, LLC
ER02–198, 001, Mirant Delta, LLC and Mirant Potrero, LLC
ER02–198, 002, Mirant Delta, LLC and Mirant Potrero, LLC
ER02–198, 003, Mirant Delta, LLC and Mirant Potrero, LLC
E–20.
Docket# ER01–2201, 000, Entergy Services, Inc.
Other#s EL02–46, 000, Generator Coalition v. Entergy Services, Inc.
E–21.
Docket# ER03–119, 000, Southern Operating Services, Company
ER03–120, 000, Alabama Power Company
ER03–121, 000, Alabama Power Company
ER03–122, 000, Mississippi Power Company
ER03–123, 000, Southern Operating Services, Company
ER03–124, 000, Southern Operating Services, Company
ER03–125, 000, Southern Operating Services, Company
ER03–126, 000, Southern Operating Services, Company
ER03–127, 000, Southern Operating Services, Company
ER03–128, 000, Southern Operating Services, Company
ER03–129, 000, Southern Operating Services, Company
ER03–130, 000, Georgia Power Company
ER03–131, 000, Georgia Power Company
ER03–135, 000, Gulf Power Company
ER03–136, 000, Gulf Power Company
E–22.
Omitted
E–23.
Docket# ER02–1784, 001, NorthWestern Energy, L.L.C.
Other#s SC00–1, 004, NorthWestern Energy, L.L.C.
E–24.
Docket# EL02–103, 000, City of Vernon, California
Other#s EL02–103, 001, City of Vernon, California
E–25.
Docket# ER97–2358, 000, Pacific Gas and Electric Company
Other#s ER98–2351, 000, Pacific Gas and Electric Company
E–26.
Docket# ER02–1974, 000, Midwest Independent Transmission System Operator, Inc.
Other#s ER02–1975, 000, Midwest Independent Transmission System Operator, Inc.
E–27.
Omitted
E–28.
Docket# ER02–1705, 002, Southwest Power Pool, Inc.
E–29.
Docket# EL02–89 001, Tenaska Power Services Company v. Southwest Power Pool, Inc.
E–30.
Docket# EL02–95, 001, Constellation Power Source, Inc. v. American Electric Power Service Corporation and Southwest Power Pool, Inc.
Other#s ER02–2028, 001, American Electric Power Service Corporation
E–31.
Docket# ER02–2321, 002, California Independent System Operator Corporation
E–32.
Omitted
E–33.
Docket# ER02–485, 002, Midwest Independent Transmission System Operator, Inc.
E–34.
Omitted
E–35.
Docket# EL02–121, 001, Occidental Chemical Corporation v. PJM Interconnection, L.L.C., and Delmarva Power and Light Company
Other#s EL02–121, 002, Occidental Chemical Corporation v. PJM Interconnection, L.L.C., v. PJM Interconnection, L.L.C., and Delmarva Power and Light Company
E–36.
Docket# ER02–1021, 002, Ontario Energy Trading International Corp.
E–37.
Omitted
E–38.
Docket# ER03–15, 001, Consumers Energy Company
E–39.
Docket# EL02–128, 000, Sithe New England, LLC v. ISO New England, Inc.
E–40.
Docket# EL03–25, 000, NSTAR Electric and Gas Corporation, Central Vermont Public Service Corporation, PPL Energy Plus, LLC, United Illuminating Company, Unitil Power Corp., and Fitchburg Gas and Electric Light Company v. New England Power Pool
E–41.
Docket# EL03–29, 000, PG&E Energy Trading-Power, L.P. v. California Power Exchange Corporation
E–42.
Docket# EC02–113, 000, Cinergy Services, Inc. on behalf of PSI Energy, Inc., CinCap Madison, LLC and CinCap VII, LLC
E–43.
Docket# EL02–117, 000, City of Burbank, California v. Calpine Energy Services,L.P., Duke Energy Trading and Marketing, L.L.C. and El Paso Merchant Energy, L.P.
Other#s EL02–119, 000, The Kroger Co., v. Dynegy Power Marketing, Inc.

Miscellaneous Agenda

M–1.
Docket# RM03–5, 000, Amendment to Delegations of Authority to the Chief Administrative Law Judge
G–1.
Docket# GT02–38, 002, Northern Natural Gas Company
Other#s
GT02–38, 001, Northern Natural Gas Company
GT02–38, 003, Northern Natural Gas Company
G–2.
Docket# GT02–35, 000, Tennessee Gas Pipeline Company
Other#s GT02–35, 001, Tennessee Gas Pipeline Company
G–3.
Docket# RP02–363, 003, North Baja Pipeline LLC
G–4.
Omitted
G–5.
Docket# OR02–13, 000, SFPP, L.P.
G–6.
Docket# OR92–8, 017, SFPP, L.P.
Other#s OR92–8, 018, SFPP, L.P.
OR92–8, 019, SFPP, L.P.
OR93–5, 014, SFPP, L.P.
OR93–5, 015, SFPP, L.P.
OR93–5, 016, SFPP, L.P.
OR94–3, 013, SFPP, L.P.
OR94–3, 014, SFPP, L.P.
OR94–3, 015, SFPP, L.P.
OR94–4, 015, SFPP, L.P.
OR94–4, 016, SFPP, L.P.
OR94–4, 017, SFPP, L.P.
OR95–5, 012, Mobil Oil Corporation v. SFPP, L.P.
OR95–5, 013, Mobil Oil Corporation v. SFPP, L.P.
OR95–5, 014, Mobil Oil Corporation v. SFPP, L.P.
OR95–34, 011, Tosco Corporation v. SFPP, L.P.
OR95–34, 012, Tosco Corporation v. SFPP, L.P.
OR95–34, 013, Tosco Corporation v. SFPP, L.P.
IS99–144, 009, SFPP, L.P.
IS99–144, 010, SFPP, L.P.
IS99–144, 011, SFPP, L.P.
IS00–379, 009, SFPP, L.P.
IS00–379, 010, SFPP, L.P.
IS00–379, 011, SFPP, L.P.
IS02–46, 002, SFPP, L.P.
IS02–46, 003, SFPP, L.P.
IS02–46, 004, SFPP, L.P.
IS02–82, 002, SFPP, L.P.

IS02–82, 003, SFPP, L.P.
IS02–82, 004, SFPP, L.P.
G–7.
Docket# RP02–492, 002, Algonquin Gas Transmission Company
Other#s RP02–492, 001, Algonquin Gas Transmission Company
G–8.
Docket# RP02–494, 002, Texas Eastern Transmission, L.P.
Other#s RP02–494, 001, Texas Eastern Transmission, L.P.
G–9.
Docket# RP02–489, 002, Maritimes & Northeast Pipeline, L.L.C.
Other#s RP02–489, 001, Maritimes & Northeast Pipeline, L.L.C.
G–10.
Docket# RP02–493, 002, East Tennessee Natural Gas Company
Other#s RP02–493, 001, East Tennessee Natural Gas Company
G–11.
Docket# RP02–425, 002, Texas Gas Transmission Corporation
Other#s RP02–425, 001, Texas Gas Transmission Corporation
G–12.
Docket# RP02–427, 001, Williams Gas Pipelines Central, Inc.
Other#s RP02–427, 002, Williams Gas Pipelines Central, Inc.
G–13.
Docket# RP02–318, 000, Questar Southern Trails Pipeline Company
Other#s RP02–318, 001, Questar Southern Trails Pipeline Company
G–14.
Docket# RP96–200, 092, CenterPoint Energy Gas Transmission Company (formerly Reliant Energy Gas Transmission Company)
G–15.
Docket# RP99–176, 075, Natural Gas Pipeline Company of America
G–16.
Omitted
G–17.
Docket# RP03–218, 000, Colorado Interstate Gas Company
G–18.
Docket# RP03–195, 000, Dominion Transmission, Inc.
G–19.
Docket# RP03–189, 000, Great Lakes Gas Transmission Limited Partnership
G–20.
Docket# RP03–228, 000, Alliance Pipeline L.P.
G–21.
Docket# RP03–210, 000, Guardian Pipeline, L.L.C.
G–22.
Docket# RP03–221, 000, High Island Offshore System, L.L.C.
G–23.
Docket# RP03–217, 000, Wyoming Interstate Company, Ltd.
G–24.
Docket# RP03–222, 000, Columbia Gas Transmission Corporation
G–25.
Docket# RP00–488, 001, Portland Natural Gas Transmission System
Other#s RP01–50, 002, Portland Natural Gas Transmission System
RP03–179, 000, Portland Natural Gas Transmission System
G–26.
Docket# RP03–17, 000, Missouri Interstate Gas, L.L.C.
G–27.
Docket# RP02–99, 005, Shell Offshore Inc., v. Transcontinental Gas Pipeline Corp., Williams Gas Processing-Gulf Coast Co., L.P., Williams Field Services Co., and Williams Gulf Coast Gathering Co., L.L.C.
G–28.
Docket# RP03–16, 001, Pan-Alberta Gas (US) Inc., and Mirant Americas Energy Marketing, L.P. v. Northern Border Pipeline Company
G–29.
Docket# RP00–411, 003, Iroquois Gas Transmission System, L.P.
Other#s RP01–44, 005, Iroquois Gas Transmission System, L.P.
G–30.
Docket# RP01–35, 001, Norteño Pipeline Company
Other#s RP01–92, 001, Norteño Pipeline Company
G–31.
Docket# RP02–561, 002, CenterPoint Energy Gas Transmission (formerly Reliant Energy Gas Transmission Company)
G–32.
Docket# RP02–123, 000, Williams Gas Pipelines Central, Inc.
Other#s RP03–116, 000, Williams Gas Pipelines Central, Inc.
G–33.
Docket# GP99–16, 000, Northern Natural Gas Company
Other#s GP99–17, 000, Northern Natural Gas Company
G–34.
Docket# RP99–518, 032, PG&E Gas Transmisson, Northwest Corporation
G–35.
Docket# RP00–325, 002, Colorado Interstate Gas Company
Other#s RP01–38, 002, Colorado Interstate Gas Company
G–36.
Omitted
G–37.
Docket# RP02–179, 003, Williams Gas Pipelines Central, Inc.
G–38.
Docket# RP02–216, 003, Reliant Energy Gas Transmission Company
G–39.
Omitted
G–40.
Docket# RP00–632, 011, Dominion Transmission, Inc.
G–41.
Docket# RP01–620, 000, Transwestern Pipeline Company v. Southern California Gas Company
G–42.
Docket# RP97–288, 009, Transwestern Pipeline Company
Other#s RP97–288, 010, Transwestern Pipeline Company
RP97–288, 011, Transwestern Pipeline Company
RP97–288, 012, Transwestern Pipeline Company
RP97–288, 013, Transwestern Pipeline Company
RP97–288, 014, Transwestern Pipeline Company
RP97–288, 015, Transwestern Pipeline Company
RP97–288, 016, Transwestern Pipeline Company
RP97–288, 017, Transwestern Pipeline Company
RP97–288, 018, Transwestern Pipeline Company
RP97–288, 019, Transwestern Pipeline Company
RP97–288, 020, Transwestern Pipeline Company
RP97–288, 022, Transwestern Pipeline Company
RP97–288, 024, Transwestern Pipeline Company
RP97–288, 025, Transwestern Pipeline Company
RP97–288, 026, Transwestern Pipeline Company
RP97–288, 027, Transwestern Pipeline Company
RP01–507, 000, Transwestern Pipeline Company
RP01–507, 001, Transwestern Pipeline Company
RP01–507, 002, Transwestern Pipeline Company
G–43. Docket# RP98–54 035 Colorado Interstate Gas Company
Other#s SA98–96, 000, IMC Global Operations Inc.
G–44.
Docket# OR02–6, 000, Sinclair Oil Corporation v. Rocky Mountain Pipeline System LLC and BP Pipelines (North America), Inc.
G–45.
Docket# OR03–1, 000, Phillips Petroleum Company v. Platte Pipe Line Company
Other#s OR02–5, 002, Big West Oil, LLC
OR02–8, 002, Express Pipeline LLC
IS02–384, 000, Platte Pipe Line Company

Energy Projects—Hydro

H–1.
Docket# P–2318, 017, Erie Boulevard Hydropower, L.P.
Other#s P–2047, 017, Erie Boulevard Hydropower, L.P.
P–2482, 038, Erie Boulevard Hydropower, L.P.
P–2554, 020, Erie Boulevard Hydropower, L.P.
P–12252, 001, Hudson River-Black River Regulating District
H–2.
Docket# P–4718, 026, Cocheco Falls Associates
H–3.
Docket# P–10855, 003, Upper Peninsula Power Company
H–4.
Docket# P–2589, 027, Marquette Board of Light and Power
H–5.
Docket# P–2661, 018, Pacific Gas and Electric Company
H–6.
Docket# P–2616, 025, Erie Boulevard Hydropower, L.P.
H–7.

Docket# P–4632, 027, Clifton Power Corporation

H–8.

Docket# P–5, 072, PPL Montana, LLC and Confederated Salish and Kootenai Tribes of the Flathead Nation

H–9.

Docket# P–2738 049 New York State Electric & Gas Corporation

Energy Projects—Certificates

C–1.

Omitted

C–2.

Docket# CP02–420, 000, Red Lake Gas Storage, L.P.

Other#s CP02–421, 000, Red Lake Gas Storage, L.P.

CP02–422, 000, Red Lake Gas Storage, L.P.

C–3.

Docket# CP02–430, 000, Saltville Gas Storage Company, LLC

C–4.

Docket# CP02–1, 002, Southern Natural Gas Company

C–5.

Docket# CP02–99, 001, Transcontinental Gas Pipe Line Corporation

C–6.

Docket# CP02–31, 001, Iroquois Gas Transmission System, L.P.

C–7.

Docket# CP02–141, 000, Transcontinental Gas Pipe Line Corporation

Magalie R. Salas,

Secretary.

[FR Doc. 03–2010 Filed 1–24–03; 11:15 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7442–3]

Notice of Proposed Purchaser Agreement Pursuant to the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as Amended by the Superfund Amendments and Reauthorization Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice; request for public comment.

SUMMARY: In accordance with the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended by the Superfund Amendments and Reauthorization Act of 1986 (''CERCLA''), 42 U.S.C. 9601–9675, notice is hereby given that a proposed purchaser agreement (''Purchaser Agreement'') associated with the Commodore Semiconductor Group Superfund Site (''Site'') located in Norristown, Pennsylvania, was executed by the Environmental Protection Agency and the Department of Justice and is now subject to public comment, after which the United States may modify or withdraw its consent if comments received disclose facts or considerations which indicate that the Purchaser Agreement is inappropriate, improper, or inadequate. The Purchaser Agreement will resolve certain potential EPA claims under sections 106 and 107 of CERCLA, 42 U.S.C. 9606 and 9607, against 950 Rittenhouse, Inc., and 950 Rittenhouse Associates, L.P. (''Purchaser''). The property subject to the Purchaser Agreement is the Site which encompasses approximately 14 acres at 950 Rittenhouse Road, in the Valley Forge Corporate Center in Lower Providence Township, Norristown, Pennsylvania. A portion of the Site had been operated as a semiconductor chip manufacturing facility. At the time the building was constructed, a 250-gallon underground concrete storage tank was installed adjacent to the southeast side of the building. The concrete tank was used to store a waste solution known to contain trichloroethene (''TCE'') and other solvents. According to information obtained by EPA from Commodore Business Machines, Inc., the former operator of the Facility, contents from the underground concrete storage tank leaked in 1974.

In February 1984, EPA performed a Site Inspection (''SI'') at the Site. A Preliminary Assessment (''PA'') and another SI were subsequently completed by EPA on December 5 and 12, 1986, respectively. Sampling results revealed the presence of trichloroethene (''TCE'') in nearby residential wells. EPA also found the presence of volatile organic compounds (''VOCs'') which include trichloroethene (''TCE''), trichloroethane (''TCA''), 1,2 dichloroethene, 1,1 dichloroethene, and 1,1 dichloroethane and vinyl chloride in groundwater, surface water, and soil samples taken from the Site.

For thirty (30) days following the date of publication of this notice, the Agency will accept written comments relating to the proposed Purchaser Agreement. The Agency's response to any comments received will be available for public inspection at the U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, PA 19103.

DATES: Comments must be submitted on or before February 27, 2003.

AVAILABILITY: The proposed Purchaser Agreement and additional background information relating to the proposed Purchaser Agreement are available for public inspection at the U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, PA 19103. A copy of the proposed Purchaser Agreement may be obtained from Suzanne Canning, U.S. Environmental Protection Agency, Legal Program Coordinator (3RC00), 1650 Arch Street, Philadelphia, PA 19103. Comments should reference the ''Commodore Semiconductor Group Superfund Site Prospective Purchaser Agreement'' and ''EPA Docket No. CERCLA–03–2002–0071,'' and should be forwarded to Suzanne Canning at the above address.

FOR FURTHER INFORMATION CONTACT: Yvette Hamilton-Taylor (3RC43), Senior Assistant Regional Counsel, U.S. Environmental Protection Agency, 1650 Arch Street, Philadelphia, PA 19103, Phone: (215) 814–2636.

Dated: December 30, 2002.

Thomas Voltaggio,

Acting Regional Administrator, Region III.

[FR Doc. 03–1866 Filed 1–27–03; 8:45 am]

BILLING CODE 6560–50–P

EXPORT-IMPORT BANK OF THE UNITED STATES

Economic Impact Policy

This notice is to inform the public that the Export-Import Bank of the United States has received an application to finance the export of $25 million of U.S. goods and services to a buyer in Russia. According to the foreign buyer, the U.S. exports will enable the Russian company to produce an additional 1.2 million metric tons metallurgical coal, the entirety of which will be consumed domestically in Russia. Interested parties may submit comments on this transaction by e-mail to *economic.impact@exim.gov* or by mail to 811 Vermont Avenue, NW., Room 1238, Washington, DC 20571, within 14 days of the date this notice appears in the Federal Register.

Helene S. Walsh,

Director, Policy Oversight and Review.

[FR Doc. 03–1854 Filed 1–27–03; 8:45 am]

BILLING CODE 6690–01–M

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission for Extension Under Delegated Authority, Comments Requested

January 16, 2003.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden

invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Public Law 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Persons wishing to comment on this information collection should submit comments March 28, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Judy Boley Herman, Federal Communications Commission, 445 12th Street, SW., Room 1–C804, Washington, DC 20554 or via the internet to *jboley@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collections contact Judy Boley Herman at 202–418–0214 or via the internet at *jboley@fcc.gov.*

SUPPLEMENTARY INFORMATION: *OMB Control No.:* 3060–0732.

Title: Consumer Education Concerning Wireless E911.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 2,500.

Estimated Time Per Response: 2 hours.

Frequency of Response: On occasion reporting requirement.

Total Annual Burden: 1,563 hours.

Annual Reporting and Recordkeeping Cost Burden: $375,000.

Needs and Uses: Commission rules proposes a consumer education program to address a concern that consumers may not have a sufficient understanding of technological limitations that can impede the transmission of wireless 911 calls and the delivery of emergency assistance. The Commission believes that wireless carriers have an obligation to inform customers regarding the scope of their services, including any technical limitations that can impede transmission of wireless services in providing access to 911. The information will be used by consumers to determine rationally and accurately the scope of their options in accessing 911 services from mobile handsets.

OMB Control No.: 3060–0755.

Title: Infrastructure Sharing—47 CFR 59.1—59.4.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities.

Number of Respondents: 75 respondents; 1,425 responses.

Estimated Time Per Response: 2 hours.

Frequency of Response: On occasion reporting requirement, third party disclosure requirement.

Total Annual Burden: 2,325 hours.

Annual Reporting and Recordkeeping Cost Burden: N/A.

Needs and Uses: The Commission implemented the infrastructure sharing provisions of the Communications Act of 1934, as amended by the Telecommunication Act of 1996. Section 259 requires incumbent local exchange carriers (LECs) to file any arrangements showing the conditions under which they share infrastructure per section 259. Section 259 also requires incumbent LECs to provide information on deployment of new services and equipment to qualifying carriers. The Commission also requires incumbent LECs to provide 60 day notices prior to terminating section 259 agreements.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1838 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission

January 16, 2003.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Public Law 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before February 27, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Judith Boley Herman, Federal Communications Commission, Room 1–C804, 445 12th Street, SW., DC 20554 or via the Internet to *jboley@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s), contact Judith Boley Herman at 202–418–0214 or via the Internet at *jboley@fcc.gov.*

SUPPLEMENTARY INFORMATION:

OMB Control No.: 3060–0106.

Title: Section 43.61—Reports of Overseas Telecommunications Traffic.

Form No: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit.

Number of Respondents: 704.

Estimated Time Per Response: 26 hours.

Frequency of Response: On occasion, quarterly, and annual reporting requirements.

Total Annual Burden: 18,520 hours.

Total Annual Cost: $626,000.

Needs and Uses: The telecommunications traffic data report is an annual reporting requirement imposed on common carriers engaged in

the provision of overseas telecommunications services. The reported data is useful for international planning, facility authorization, monitoring emerging developments in communications services, analyzing market structures, tracking the balance of payments in international communications services, ad market analysis purposes. The reported data enables the Commission to fulfill it's regulatory responsibilities.

OMB Control No.: 3060–0848.

Title: Deployment of Wireline Services Offering Advanced Telecommunications Capability, CC Docket No. 989–147.

Form No: N/A.

Type of Review: Revision of a currently approved collection.

Respondents: Business or other for-profit.

Number of Respondents: 1,750.

Estimated Time Per Response: .50–44 hours.

Frequency of Response: On occasion and annual reporting requirements, recordkeeping requirement, third party disclosure requirement.

Total Annual Burden: 165,600 hours.

Total Annual Cost: N/A.

Needs and Uses: The requirements implemented section 251 of the Communications Act of 1934, as amended, to promote deployment of advanced services without significantly degrading the performance of other services. All the requirements will be used by the Commission and competitive local exchange carriers (CLECs) to facilitate the deployment of advanced data services and implement section 251 of the Act. This information collection was revised to because it clarified in an Order on Reconsideration that incumbent LECs must file tariffs for cross-connects provided pursuant to section 201.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1839 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission

January 15, 2003.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Public Law 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before February 27, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Judith Boley Herman, Federal Communications Commission, Room 1–C804, 445 12th Street, SW., DC 20554 or via the Internet to *jboley@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s), contact Judith Boley Herman at 202–418–0214 or via the Internet at *jboley@fcc.gov.*

SUPPLEMENTARY INFORMATION: *OMB Control No.:* 3060–0972.

Title: Multi-Association Group (MAG) Plan for Regulation of Interstate Services of Non-Price Cap Incumbent Local Exchange Carriers and Interexchange Carriers.

Form No: FCC Forms 507, 508, and 509.

Type of Review: Revision of a currently approved collection.

Respondents: Business or other for-profit, not-for-profit institutions.

Number of Respondents: 1,300 respondents; 5,555 responses.

Estimated Time Per Response: 1–93 hours.

Frequency of Response: On occasion, annual, quarterly, and one-time reporting requirements, third party disclosure requirement.

Total Annual Burden: 31,725 hours.

Total Annual Cost: $45,000.

Needs and Uses: The Commission revised the filing requirements associated with the Interstate Common Line Support (ICLS) mechanism for rate-of-return carriers. This revision created new FCC forms 508 and 509 to this information collection to ease the burden on the carriers, adds projected and actual revenue data to the existing collection of projected and actual cost data and provides for the collection of certain data for validation purposes. The information is used by the Commission to determine whether and to what extent non-price cap or rate-of-return carriers providing data are eligible to receive universal service support. The Commission will use the tariff data to make sure that rates are just and reasonable, as required by section 201(b) of the Act.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1840 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission

January 8, 2003.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Pub. L. 104–13. An agency may not conduct or sponsor a collection of information unless it displays a current valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before March 31, 2003.

If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Les Smith, Federal Communications Commission, Room 1–A804, 445 12th Street, SW., Washington, DC 20554, or via the Internet to *lesmith@fcc.gov*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s) contact Les Smith at (202) 418–0217 or via the Internet at *lesmith@fcc.gov*.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0017.

Title: Application for a Low Power TV, Translator, or TV Booster Station License.

Form Number: FCC Form 347.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities; individuals or households; State, local or Tribal Government.

Number of Respondents: 1,000.

Estimated Time per Response: 1.5 hours.

Frequency of Response: On occasion reporting requirements.

Total Annual Burden: 1,500 hours.

Total Annual Costs: $110,000.

Needs and Uses: Permittees of low power television, TV translator, or TV booster stations use FCC Form 347 to apply for a station license. The FCC staff use the data to confirm that the station was built to terms specified in the outstanding construction permit and to process the applicant's license to operate the station.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1841 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–10–P

FEDERAL COMMUNICATIONS COMMISION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission

December 12, 2002.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Pub. L. 104–13. An agency may not conduct or sponsor a collection of information unless it displays a current valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before March 31, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Les Smith, Federal Communications Commission, Room 1–A804, 445 12th Street, SW., Washington, DC 20554, or via the Internet to *lesmith@fcc.gov*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s) contact Les Smith at (202) 418–0217 or via the Internet at *lesmith@fcc.gov.*

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0161.

Title: Section 73.61, AM Directional Antenna Field Strength Measurements.

Form Number: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business and other for-profit entities.

Number of Respondents: 1,890.

Estimated Time per Response: 4 hours.

Frequency of Response: Recordkeeping.

Total Annual Burden: 36,020 hours.

Total Annual Costs: None.

Needs and Uses: 47 CFR 73.61 requires each AM station using directional antennas to make field strength measurement as often as necessary to ensure proper directional antenna system operation. Stations not having approved sampling systems make field strength measurements every three months. Stations with approved sampling systems must take field strength measurements as often as necessary. Also, all AM station using directional signals must take partial proofs of performance as often as necessary. The FCC staff used the data in field inspections/investigations; AM licensees with directional antennas use the data to ensure that adequate interference protection is maintained between stations and to ensure proper operation of antennas.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1842 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–10–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission for Extension Under Delegated Authority; Comments Requested

December 13, 2002.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Pub.L 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Persons wishing to comment on this information collection should submit comments on or before March 31, 2003.

ADDRESSES: Direct all comments to Les Smith, Federal Communications Commission, Room 1–A804, 445 12th Street, SW., Washington, DC 20554, or via the Internet to *lesmith@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collections contact Les Smith at (202) 418–0217 or via the Internet at *lesmith@fcc.gov.*

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0178.

Title: Section 73.1560, Operating Power and Mode Tolerances.

Form Number: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business and other for-profit entities.

Number of Respondents: 280.

Estimated Time per Response: 1 hour.

Frequency of Response: On occasion reporting requirements.

Total Annual Burden: 280 hours.

Total Annual Costs: None.

Needs and Uses: 47 CFR 73.1560 requires licensees of AM, FM or TV broadcast stations to file a notification with the FCC when operating at reduced power for ten consecutive days and upon restoration of normal operations, A licensee must also file an informal written request for additional time when operation cannot be restored within 30 days due to circumstances beyond the licensee's control. The FCC staff use these data to maintain complete and accurate data about station operations.

OMB Control Number: 3060–0181.

Title: Section 73.1615, Operation During Modification of Facilities.

Form Number: N/A.

Type of Review: Extension of currently approved collection.

Respondents: Business or other for-profit entities.

Number of Respondents: 110.

Estimated Time per Response: 20–60 mins.

Frequency of Response: On occasion reporting requirements.

Total annual burden: 27 hours.

Total Annual Costs: $6,000.

Needs and Uses: 47 CFR 73.1615(c) requires the licensee of an AM, FM, or TV station to notify to the FCC when it is in the process of modifying existing facilities as authorized by a construction permit, and it becomes necessary either to discontinue operation or to operate with temporary facilities. If the licensee needs to discontinue operations or to operate with temporary facilities for more than 30 days, then an informal letter request must be sent to the FCC prior to the 30th day. Section 73.1615(d) requires the licensee of an AM station holding a construction permit, which authorizes both a change in frequency and directional facilities, to obtain authority from the FCC prior to using any new installation authorized by the permit, or using temporary facilities. This request is to be made by letter 10 days prior to the date on which the temporary operation is to commence. This letter shall describe the operating modes and facilities to be used. The FCC staff use the data to maintain complete technical records and to ensure that interference will not be caused by other licensed broadcast facilities.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1843 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission

December 24, 2002.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Pub. L. 104–13. An agency may not conduct or sponsor a collection of information unless it displays a current valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before March 31, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Les Smith, Federal Communications Commission, Room 1–A804, 445 12th Street, SW., Washington, DC 20554, or via the Internet to *lesmith@fcc.gov*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s) contact Les Smith at 202–418–0217 or via the Internet at *lesmith@fcc.gov.*

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0506.

Title: Application for FM Broadcast Station License, Form 302–FM.

Form Number: FCC 302–FM.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities; Not-for-profit institutions.

Number of Respondents: 925.

Estimated Time per Response: 2–4 hours.

Frequency of Response: On occasion reporting requirements.

Total Annual Burden: 1,840 hours.

Total Annual Costs: $665,500.

Needs and Uses: On October 2, 1998, the FCC adopted a Report and Order (R&O) in MM Docket Nos. 98–43 and 94–149. Among other things, the R&O substantially revised the FCC Form 302–FM to facilitate electronic filing by using certifications and an engineering technical box; simplifying questions; and providing instructions for processing standards and rule interpretations. These changes reduced the applicant's filing burdens when preparing and submitting supporting exhibits and streamlined the Commission's application processing. The Commission has also begun to audit pre- and post-application grants at random to preserve the application process' integrity. The FCC uses the data to confirm that each station has been built as specified in the construction permit; to update FCC station files; and for inclusion in future station operating licenses.

OMB Control Number: 3060–0627.

Title: Application for AM Broadcast Station License, FCC Form 302–AM.

Form Number: FCC 302–AM.

Type of Review: Extension of currently approved collection.

Respondents: Business or other for-profit entities; Not-for-profit institutions.

Number of Respondents: 380.

Estimated Time Per Response: 4–480 hours.

Frequency of Response: On occasion reporting requirements.

Total Annual Burden: 2,800 hours.

Total Annual Costs: $10,070.

Needs and Uses: On October 22, 1998, the Commission adopted a Report and Order (R&O) in MM Docket Nos. 98–43 and 94–149. Among other things, this

R&O revised the FCC Form 302–AM to facilitate electronic filing by using of certifications and an engineering technical box; revising questions; and adding detailed instructions for processing standards and rule interpretations. These changes reduced the applicant's filing burden when preparing and submitting supporting exhibits and allowed the Commmission to streamline its application processing. The Commission has also begun to audit pre- and post-application grants at random to preserve the application process' integrity. The FCC uses these data to confirm that each station has been built as specified in the construction permit; to update FCC station files; and for inclusion in future station operating licenses.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1844 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–10–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission, Comments Requested

January 15, 2003.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Public Law 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before March 31, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Judith Boley Herman, Federal Communications Commission, Room 1–C804 or Room 1–A804, 445 12th Street, SW., Washington, DC 20554 or via the Internet to *jboley@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s), contact Judith Boley Herman at 202–418–0214 or via the Internet at *jboley@fcc.gov.*

SUPPLEMENTARY INFORMATION:

OMB Control No.: 3060–0850.

Title: Quick-Form Application for Authorization in the Ship, Aircraft, Amateur, Restricted and Commercial Operator, and General Mobile Radio Services.

Form No.: FCC Form 605.

Type of Review: Revision of a currently approved collection.

Respondents: Individual or households, business or other for-profit, not-for-profit institutions, and state, local or tribal government.

Number of Respondents: 175,000.

Estimated Time Per Response: .44 hours.

Frequency of Response: On occasion reporting requirement, third party disclosure requirement.

Total Annual Burden: 77,000 hours.

Total Annual Cost: $2,537,500.

Needs and Uses: FCC Form 605 is a consolidated application for Ship, Aircraft, Amateur, Restricted and Commercial Radio Operators, and General Mobile Radio Services and is used to collect licensing date for the Universal Service Licensing System (ULS).

The form is being revised to incorporate additional data fields in accordance with the recommendation in International Maritime Organization (IMO) Assembly Resolution A.887 (21) submitted by the National GMDSS Implementation Task Force (charted by the United States Coast Guard); to change certain certification statements into questions giving applicants an option to clarify if a license is required; and to clarify existing instructions for the general public. The data collected on this form includes the date of birth for Commercial Operator licensees, however, this information will be redacted from public view.

There is no change to the estimated average burden or the number of respondents of the additional data elements proposed by the IMO. The Task Force argues that search and rescue operations could be significantly improved if the Commission's database contained this additional information.

OMB Control No.: 3060–0910.

Title: Third Report and Order in CC Docket No. 94–102, Revision of the Commission's Rules to Ensure Compatibility with Enhanced 911 Emergency Calling Systems.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit, not-for-profit institutions.

Number of Respondents: 4,000.

Estimated Time Per Response: 2 hours.

Frequency of Response: On occasion and one-time reporting requirements.

Total Annual Burden: 8,000 hours.

Total Annual Cost: N/A.

Needs and Uses: Commission rules allows wireless carriers to permit the use of handset-based solutions, or hybrid solutions that require changes both to handsets and wireless networks, in providing caller location information as part of enhanced 911 services. The information will provide public service answering points (PSAPs), providers of location technology, investors, manufacturers, local exchange carriers, and the Commission with valuable information necessary for preparing for full Phase II E911 implementation. These advanced reports will provide helpful, if not essential, information for coordinating carrier plans with those manufacturers and PSAPs. It will also assist the Commission's efforts to monitor Phase II developments and to take necessary actions to maintain the Phase II implementation schedule.

OMB Control No.: 3060–0804.

Title: Universal Service—Health Care Providers Universal Service Program.

Form Nos.: FCC Forms 465, 466, 466–A, 467, and 468.

Type of Review: Revision of a currently approved collection.

Respondents: Business or other for-profit, not-for-profit institutions.

Number of Respondents: 5,255.

Estimated Time Per Response: 1.5–2.5 hours.

Frequency of Response: On occasion reporting requirement, third party disclosure requirement.

Total Annual Burden: 9,755 hours.

Total Annual Cost: N/A.

Needs and Uses: The Commission adopted rules providing support for all telecommunications services, Internet access, and internal connections for all eligible health care providers. Health

care providers who want to participate in the universal service program must file several form including FCC Forms 466, 467, and 468. The Commission is revising FCC Forms 466, 467 and 468.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1846 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission, Comments Requested

January 17, 2003.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Public Law 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before March 31, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Judith Boley Herman, Federal Communications Commission, Room 1–C804 or Room 1–A804, 445 12th Street, SW., Washington, DC 20554 or via the Internet to *jboley@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s), contact Judith Boley Herman at 202–418–0214 or via the Internet at *jboley@fcc.gov.*

SUPPLEMENTARY INFORMATION:

OMB Control No.: 3060–1031.

Title: Revision of the Commission's Rules to Ensure Compatibility with Enhanced 911 Emergency Calling Systems: Petition of City of Richardson, TX; Order on Reconsideration.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit, not-for-profit institutions, and state, local or tribal government.

Number of Respondents: 1,358.

Estimated Time Per Response: 2–40 hours.

Frequency of Response: On occasion reporting requirement, third party disclosure requirement.

Total Annual Burden: 13,960 hours.

Total Annual Cost: N/A.

Needs and Uses: The Order on Reconsideration responds to two petitions for reconsideration of a previous Order which responded to a petition from the city of Richardson, TX. The current Order on Reconsideration contains three new information collection requirements. First, it allows wireless carriers to toll the six-month E911 implementation period if the carrier certifies that the requesting Public Safety Answering Point (PSAP) is not E911 capable. Second, PSAPs may file a response to the carrier's certification. Third, the Order on Reconsideration clarifies that wireless carriers and PSAPs may mutually agree on an E911 implementation date other than that prescribed in the Commission's rules.

The Commission sought and obtained emergency OMB approval for this information collection on 1/16/03. The Commission is now seeking extension of this collection to obtain the full three year OMB approval.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1848 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Submitted to OMB for Review and Approval

December 23, 2002.

SUMMARY: The Federal Communications Commissions, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection, as required by the Paperwork Reduction Act of 1995, Pub. L. 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before February 27, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Les Smith, Federal Communications Commission, Room 1–A804, 445 12th Street, SW., Washington, DC 20554 or via the Internet to *lesmith@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collections contact Les Smith at (202) 418–0217 or via the Internet at *lesmith@fcc.gov.*

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0010.

Title: Local Franchising Authority.

Form Number: FCC 323.

Type of Review: Revision of a currently approved collection.

Respondents: State, local, or tribal Governments.

Number of Respondents: 2,000.

Estimated Time per Response: 0.5 to 1.5 hours.

Frequency of Response: On occasion, biennial, and/or upon renewal reporting requirements.

Total Annual Burden: 2,750 hours.

Total Annual Cost: $2,163,000.

Needs and Uses: Each permittee of a commercial AM, FM, TV, and international broadcast station must file FCC Form 323, Ownership Report,

within 30 days of the FCC granting their application for an original construction permit, the consummation, pursuant to FCC consent, of a transfer of control or an assignment of license, and/or when they file their station's license renewal applications and every two years thereafter. A permittee/licensee must also file a report or to certify the accuracy of the current report on file, in lieu of filing a new report, when the permitted applies for a station license, or whenever there is a current and unamended FCC Form 323 on file at the FCC. Data on FCC Form 323 help to determine whether the licensee/permittee meets the FCC's multiple ownership requirements and complies with the Communications Act. The form's race/ethnicity/gender question indicates current minority and female ownership of broadcast facilities and the efficacy of FCC Rules to promote opportunities for small businesses and minority and female-owned businesses in the broadcasting industry.

OMB Control Number: 3060–0550.

Title: Local Franchising Authority.

Form Number: FCC 328.

Type of Review: Revision of a currently approved collection.

Respondents: State, local, or tribal Governments.

Number of Respondents: 20.

Estimated Time per Response: 0.5 hours.

Frequency of Response: One time reporting requirement; Third party disclosure.

Total Annual Burden: 20 hours.

Total Annual Cost: None.

Needs and Uses: The FCC developed FCC Form 328 to provide a standardized, simple form for Local Franchise Authorities (LFAs) to use when requesting certification. The Commission uses the data derived from the Form 328 filing to ensure that the LFA has met the criteria specified in section 3(a) of the Cable Television Consumer Protection Act of 1992 for regulating basic cable service rates. The Commission has made several modifications to Form 328 to update it.

OMB Control Number: 3060–1015.

Title: Ultra Wideband Transmission Systems Operating Under part 15.

Form Number: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities.

Number of Respondents: 500.

Estimated Time per Response: 2 hours.

Frequency of Response: On occasion reporting requirement; Third party disclosure.

Total Annual Burden: 1,000 hours.

Total Annual Cost: None.

Needs and Uses: 47 CFR 15.2525 requires operators of Ultra Wideband (UWB) transmission systems to coordinate their operations to avoid interference with sensitive U.S. government radio systems. Initial operation in a particular area may not commence until authorized by the FCC. The UWB operators must provide the name, address, and other pertinent contact information of the user, the desired geographical area of operation, the FCC ID number, time period during which operations will take place, and other nomenclature of the UWB device. The FCC collects this information and forwards it to the National Telecommunications and Information Administration (NTIA under the U.S. Department of Commerce). This information collection is essential to control potential interference to Federal radio communications. (Please note that on June 12, 2002, OMB approved this collection under the ''emergency processing'' provisions of the Paperwork Reduction Act of 1995, 44 U.S.C. 3507.)

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1845 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Submitted to OMB for Review and Approval

January 15, 2003.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection, as required by the Paperwork Reduction Act of 1995, Public Law 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written comments should be submitted on or before February 27, 2003. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all comments to Les Smith, Federal Communications Commissions, Room 1–A804, 445 12th Street, SW., Washington, DC 20554 or via the Internet to *lesmith@fcc.gov*.

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collections contact Les Smith at (202) 418–0217 or via the Internet at *lesmith@fcc.gov*.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0636.

Title: Equipment Authorization—Declaration of Compliance, Parts 2 and 15.

Form Number: N/A.

Type of Review: Reinstatement without change of a previously approved collection for which approval has expired.

Respondents: Business or other for-profit entities.

Number of Respondents: 4,000.

Estimated Time per Response: 19 hours (avg.).

Frequency of Response: Recordkeeping; One-time reporting requirement; Third party disclosure.

Total Annual Burden: 76,000 hours.

Total Estimated Cost: $12,000,000.

Needs and Uses: The equipment authorization procedure requires the manufacturer or equipment supplier to test the product to ensure compliance with technical standards for limiting radio frequency emissions and to include a declaration of compliance (DoC) with the standards in the literature furnished with the equipment. Testing and compliance documentation aid in controlling potential interference to radio communications. The test data may be used to investigate complaints of harmful interference; to determine that the equipment marketed complies with the applicable FCC; and to insure that the operation of the equipment is consistent with the documented test results. FCC rules require the responsible party to make the statement of compliance and supporting technical data available to the Commission upon request. The FCC rules also authorize

personal computers based on tests and approval of their individual components, without further testing of the completed assembly.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 03–1847 Filed 1–27–03; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL DEPOSIT INSURANCE CORPORATION

Agency Information Collection Activities: Submission For OMB Review; Comment Request

AGENCY: Federal Deposit Insurance Corporation (FDIC).

ACTION: Notice of information collection to be submitted to OMB for review and approval under the Paperwork Reduction Act of 1995.

SUMMARY: In accordance with requirements of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the FDIC hereby gives notice that it plans to submit to the Office of Management and Budget (OMB) a request for OMB review and approval of the following information collection systems described below.

1. *Type of Review:* Renewal of a currently approved collection.

Title: Interagency Notice of Change in Control.

OMB Number: 3064–0019.

Form Number: 6822/01.

Annual Burden

Estimated annual number of respondents: 40.

Estimated time per response: 30 hours.

Total annual burden hours: 1,200 hours.

Expiration Date of OMB Clearance: January 31, 2003.

SUPPLEMENTARY INFORMATION: The interagency notice of change in control is submitted regarding any person proposing to acquire ownership control of an insured state nonmember bank . The information is used by the FDIC to determine whether the competence, experience, or integrity of any acquiring person, indicates that it would not be in the interest of the depositors of the bank or in the interest of the public, to permit such persons to control the bank.

2. *Type of Review:* Renewal of a currently approved collection.

Title: Asset Purchaser Eligibility.

OMB Number: 3064–0135.

Annual Burden:

Estimated number of respondents: 2,500.

Estimated time per response: 30 minutes.

Total annual burden hours: 1,250 hours.

Expiration Date of OMB Clearance: January 31, 2003.

SUPPLEMENTARY INFORMATION: The Purchaser Eligibility Certification implements the statutory requirement that assets held by the FDIC in the course of liquidating any Federally insured institution not be sold to persons who contributed to the demise of an insured institution in specified ways.

OMB Reviewer: Joseph F. Lackey, Jr. (202) 395–4741, Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503.

FDIC Contact: Tamara R. Manly, (202) 898–7453, Legal Division, Room MB–3109, Federal Deposit Insurance Corporation, 550 17th Street, NW., Washington, DC 20429.

Comments: Comments on these collections of information are welcome and should be submitted on or before February 27, 2003, to both the OMB reviewer and the FDIC contact listed above.

ADDRESSES: Information about this submission, including copies of the proposed collections of information, may be obtained by calling or writing the FDIC contact listed above.

Dated: January 23, 2003.

Federal Deposit Insurance Corporation.

Robert E. Feldman,

Executive Secretary.

[FR Doc. 03–1893 Filed 1–27–03; 8:45 am]

BILLING CODE 6714–01–P

FEDERAL DEPOSIT INSURANCE CORPORATION

Notice of Agency Meeting; Sunshine Act

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 2 p.m. on Friday, January 31, 2003, 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 Board of Directors' meetings.

Summary reports, status reports, and reports of actions taken pursuant to authority delegated by the Board of Directors.

DISCUSSION AGENDA:

Memorandum and resolution re: Final Part 303 Amendment—Insurance of State Banks Chartered as Limited Liability Companies.

The meeting will be held in the Board Room on the sixth floor of the FDIC Building located at 550 17th Street, NW., Washington, DC.

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) 416–2089 (Voice); (202) 416–2007 (TTY), to make necessary arrangements.

Requests for further information concerning the matter may be directed to Mr. Robert E. Feldman, Executive Secretary of the Corporation, at (202) 898–3742.

Dated: January 24, 2003.

Federal Deposit Insurance Corporation.

Robert E. Feldman,

Executive Secretary.

[FR Doc. 03–2099 Filed 1–24–03; 3:08 pm]

BILLING CODE 6714–01–M

FEDERAL HOUSING FINANCE BOARD

Sunshine Act Notice

FEDERAL REGISTER CITATION OF PREVIOUS ANNOUNCEMENT: 68 FR 3530, January 24, 2003.

PREVIOUSLY ANNOUNCED TIME AND DATE OF THE MEETING: 3 p.m., Wednesday, January 29, 2003.

CHANGE OF MEETING TIME: Notice is hereby given that the Board of Directors meeting scheduled for 3 p.m. on Wednesday, January 29, 2003 has been changed to 10 a.m. on Wednesday, January 29, 2003.

CONTACT PERSON FOR MORE INFORMATION: Elaine L. Baker, Secretary to the Board, (202) 408–2837.

Arnold Intrater,

General Counsel.

[FR Doc. 03–2110 Filed 1–24–03; 3:33 pm]

BILLING CODE 6725–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

Declaration Regarding Administration of Smallpox Countermeasures

AGENCY: Office of the Secretary (OS), HHS.

ACTION: Notice.

SUMMARY: The Secretary of the Department of Health and Human Services is issuing this notice pursuant to section 224(p)(2)(A) of the Public Health Service Act to make a declaration regarding administration of smallpox countermeasures. The Secretary provides policy determinations regarding administration of countermeasures, and declares that a potential bioterrorist incident makes it advisable to administer, on a voluntary basis, covered countermeasures specified in the declaration for prevention or treatment of smallpox or control or treatment of adverse events related to smallpox vaccination to categories of individuals named in the declaration who may be involved in a wide range of activities associated with the administration of countermeasures against smallpox. Effective dates of the declaration, and relevant definitions are also provided.

DATES: This Notice and the attached declaration are effective as of January 24, 2003.

FOR FURTHER INFORMATION CONTACT: Jerome S. Hauer, Acting Assistant Secretary for Public Health Emergency Preparedness, (202) 205–2882.

SUPPLEMENTARY INFORMATION: The Secretary issues the following declaration pursuant to section 224(p)(2)(A) of the Public Health Service Act, 42 U.S.C. 233(p)(2)(A):

I. Policy Derterminations

(1) The attacks of September and October 2001 have heightened concern that terrorists may have access to the smallpox virus and attempt to use it against the American public and U.S. Government facilities abroad.

(2) In light of these concerns, and in order to advance the public health and national security, the President announced the smallpox vaccination program on December 13, 2002.

(3) Given the potential for a bioterrorist incident, administration of smallpox countermeasures is advisable within the terms of this declaration.

(4) Smallpox vaccine is currently recommended domestically only for smallpox response teams, health care workers, and emergency response workers.

(5) The U.S. Government is making smallpox countermeasures available to personnel associated with certain U.S. facilities abroad and administration of these countermeasures to such personnel is advisable within the terms of this declaration.

(6) Liability protections for manufacturers and distributors of smallpox countermeasures and the hospitals, health care facilities, and health care workers who will receive them and treat potentially infected smallpox cases are integral to ensuring maximum participation in the vaccination program.

(7) Section 304 of the Homeland Security Act (Pub. L. 107–296) is intended to alleviate liability concerns and therefore ensure that vaccine is available if necessary to protect the public health.

(8) Administration of a countermeasure such as smallpox vaccine is necessarily more involved than the act of placing a drop of vaccine on a two-pronged needle and inoculating a person's arm. Determining who is contraindicated; monitoring, management, and care of the countermeasure site; evaluation of countermeasure ''takes;'' and contact transmission of vaccinia, among other things, all arise out of and are directly related to and part of the administration of the countermeasure. All such acts also potentially give rise to legal liability that, without sufficient protections, may significantly discourage participation in the smallpox vaccination program.

(9) Under current domestic planning, many health care entities will designate individuals to receive countermeasures at a hospital or vaccination clinic determined by the state. To achieve a successful vaccination program and because it is impractical to have countermeasures administered at every health care entity involved in the program, it is critical that health care entities participate in this manner and that their personnel be protected while acting within their scope of employment.

(10) It is important to the successful implementation of the vaccination program that those workers employed by health care entities under whose auspices a countermeasure is administered be protected by section 304 while acting within the scope of their employment.

(11) Health care entities use numerous staffing arrangements to carry out daily functions. Individuals designated to receive covered countermeasures and subsequently treat potential smallpox cases may fall into any of these arrangements. Liability protection for these individuals, to the extent described below, is necessary to encourage participation in the smallpox vaccination program.

(12) Based upon scientific data from animal model studies examining Cidofivir's effectiveness in treating lethal pox virus infections that are similar to smallpox, Cidofivir may be useful in treating smallpox in humans.

II. Declaration

I, Tommy G. Thompson, Secretary of the Department of Health and Human Services, have concluded, in accordance with authority vested in me under section 224(p)(2)(A) of the Public Health Service Act, that a potential bioterrorist incident makes it advisable to administer, on a voluntary basis, covered countermeasures specified in this declaration for prevention or treatment of smallpox or control or treatment of adverse events related to smallpox vaccination, to categories of individuals named in this declaration. The countermeasures set forth below shall be considered to be administered pursuant to this declaration when used for prevention or treatment of smallpox, or to control or treat the adverse effects of smallpox vaccination.

This declaration may be amended as circumstances require.

III. Covered Countermeasures

Countermeasures to be administered pursuant to this declaration are:

(1) Vaccinia (Smallpox) Vaccines, including the Dryvax vaccine;

(2) Cidofivir and derivatives thereof;

(3) Vaccinia Immune Globulin (VIG).

IV. Individuals Covered by this Declaration

Individuals to whom it is advisable to administer the covered countermeasures specified above are:

(1) Health care workers who may be called upon to monitor or treat any persons who are either (a) covered by this declaration or (b) are deemed to be individuals to whom a covered countermeasure was administered by a qualified person, whether domestically or abroad, pursuant to section 224(p)(2)(C) of the Public Health Service Act;

(2) Any person who is a member of a smallpox response team or teams identified by state[s] or local government entities or the United States Department of Health and Human Services;

(3) Public safety personnel, including, but not limited to, law enforcement

officers, firefighters, security, and emergency medical personnel who may be called upon to assist smallpox response teams specified in paragraph IV(2) above; and

(4) Personnel associated with certain U.S. Government facilities abroad.

V. Effective Dates

The declaration is effective January 24, 2003 until and including January 23, 2004. The effective period may be extended or shortened by subsequent amendment to this declaration.

VI. Definitions

For the purposes of this declaration, including any claim brought against the United States pursuant to section 224 of the Public Health Service Act (''PHS''), as amended by section 304 of the Homeland Security Act, the following definitions will be used:

(1) ''Administration of a covered countermeasure'' as used in section 224(p)(1) of the PHS Act includes, but is not limited to, the physical administration of a covered countermeasure; education and screening of covered countermeasure recipients; monitoring, management, and care of the covered countermeasure site; evaluation of covered countermeasure ''takes;'' and contact transmission of vaccinia.

(2) ''Health care entity under whose auspices such countermeasure was administered'' as used in section 224(p)(7)(B)(ii) of the PHS Act, includes but is not limited to, hospitals, clinics, state and local health departments, health care entities, and contractors of any of those entities that (a) Administer covered countermeasures; (b) designate officials, agents, or employees to receive or administer covered countermeasures; or (c) are identified by state or local government entities or the United States Department of Health and Human Services to participate in the vaccination program, whether that participation is in the United States or abroad.

(3) ''Official, agent, or employee'' as used in section 224(p)(7)(B)(iv) of the PHS Act and with respect to health care entities under whose auspices covered countermeasures are administered, includes health care workers who share any employment or other staffing relationship with the health care entity.

Dated: January 24, 2003.

Tommy G. Thompson,

Secretary.

[FR Doc. 03–2012 Filed 1–24–03; 12:00 am]

BILLING CODE 4150–24–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

Findings of Scientific Misconduct

AGENCY: Office of the Secretary, HHS.

ACTION: Notice.

SUMMARY: Notice is hereby given that the Office of Research Integrity (ORI) and the Assistant Secretary for Health have taken final action in the following case:

George E. Eagan, University of Albany, State of New York: Based on the report of an investigation conducted by the University of Albany, State of New York (UA–SUNY) and additional analysis conducted by ORI in its oversight review, the U.S. Public Health Service (PHS) found that Mr. Eagan, former laboratory technician at UA–SUNY, engaged in scientific misconduct by falsification and fabrication of data supported by a subcontract to UA–SUNY on National Institute of General Medical Sciences (NIGMS), National Institutes of Health (NIH), grant R01 GM46312–11, ''Structural Biochemistry of DNA Base Excision Repair.''

Specifically, PHS found that Mr. Eagan engaged in scientific misconduct by falsifying and fabricating the data for two experiments, conducted on February 12 and 13, 2002, designed to test the survival of strains of bacteria exposed to different base analog mutagens. Mr. Eagan's experiments were significant because they would have contributed to the overall objective of the grant to understand the structural and biochemical interaction of enzymes involved in base-excision repair with various substrates, including the base analogs studied by Mr. Eagan.

Mr. Eagan has entered into a Voluntary Exclusion Agreement in which he has voluntarily agreed for a period of five (5) years, beginning on January 13, 2003:

(1) To exclude himself from any contracting or subcontracting with any agency of the United States Government and from eligibility for, or involvement in, nonprocurement transactions (*e.g.*, grants and cooperative agreements) of the United States Government referred to as ''covered transactions'' as defined in 45 CFR part 76 (Debarment Regulations); and

(2) To exclude himself from serving in any advisory capacity to PHS including but not limited to service on any PHS advisory committee, board, and/or peer review committee, or as a consultant.

Mr. Eagan had admitted to falsification of data in an earlier case.

FOR FURTHER INFORMATION CONTACT: Director, Division of Investigative Oversight, Office of Research Integrity, 5515 Security Lane, Suite 700, Rockville, MD 20852, (301) 443–5330.

Chris B. Pascal,

Director, Office of Research Integrity.

[FR Doc. 03–1920 Filed 1–27–03; 8:45 am]

BILLING CODE 4150–31–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Nominations of Topics for Evidence-based Practice Centers (EPCs)

AGENCY: The Agency for Healthcare Research and Quality (AHRQ).

ACTION: Nominations of topics for evidence reports and technology assessments.

SUMMARY: AHRQ invites nominations of topics for evidence reports and technology assessments relating to the prevention, diagnosis, treatment and management of common diseases and clinical conditions, as well as topics relating to organization and financing of health care. AHRQ's previous requests for topic nominations were published in the **Federal Register** on December 23, 1996, November 28, 1997, May 4, 1999, November 13, 2000, and February 14, 2002.

DATES: Topic nominations should be submitted by March 31, 2003 in order to be considered for the next group of evidence reports and technology assessments to be funded in Fiscal Year 2003. In addition to timely responses to this request for nominations, AHRQ also accepts topic nominations on an ongoing basis. AHRQ is not able to reply to individual responses, but will consider all nominations during the selection process. Topics selected will be announced from time to time in the **Federal Register** and through AHRQ press releases.

ADDRESSES: Topic nominations should be submitted to Jacqueline Besteman, J.D., M.A., Director, Evidence-based Practice Centers (EPC) Program, Center for Practice and Technology Assessment, AHRQ, 6010 Executive Boulevard, Suite 300, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT: Jacqueline Besteman, J.D., M.A., Center for Practice and Technology Assessment, AHRQ, 6010 Executive Blvd., Suite 300, Rockville, MD 20852; Phone: (301) 594–4017; Fax: (301) 594–

4017; Fax: (301) 594–4027; E-mail: *jbestema@ahrq.gov.*

Arrangement for Public Inspection: All nominations will be available for public inspection at the Center for Practice and Technology Assessment, telephone (301) 594–4015, weekdays between 8:30 a.m. and 5 p.m. (Eastern time).

SUPPLEMENTARY INFORMATION:

1. Background

Under Title IX of the Public Health Service Act (42 U.S.C. 299a–299c) as amended by Pub. L. 106–129 (1999), AHRQ is charged with enhancing the quality, appropriateness, and effectiveness of health care services and access to such services. AHRQ accomplishes these goals through scientific research and through promotion of improvements in clinical practice and health systems practices including the prevention of diseases and other health conditions.

2. Purpose

The purpose of **Federal Register** notice is to encourage participation and collaboration of professional societies, health systems, payors, and providers, with AHRQ as it carries out its mission to promote the practice of evidence-based health care. AHRQ serves as the science partner with private-sector and public organizations in their efforts to improve the quality, effectiveness, and appropriateness of health care delivery in the United States, and to expedite the translation of evidence-based research findings into improved health care services. AHRQ awards task order contracts to its Evidence-based Practice Centers (EPCs) to undertake scientific analyses and evidence syntheses on high-priority topics. The EPCs produce science syntheses—evidence reports and technology assessments—that provide to public and private organizations the foundation for developing and implementing their own practice guidelines, performance measures, educational programs, and other strategies to improve the quality of health care and decision-making related to the effectiveness and appropriateness of specific health care technologies and services. The evidence reports and technology assessments also may be used to inform coverage and reimbursement policies.

In addition to clinical and behavioral research, as the body of scientific studies related to the organization and financing of health care expands, systematic review and analyses of these studies can provide health system organizations with a scientific foundation for developing system-wide policies and practices. These reports may address and evaluate topics such as risk adjustment methodologies, market performance measures, provider payment mechanisms, and insurance purchasing tools, as well as provider integration of new scientific findings regarding health care and delivery innovations. To review topics that have been assigned to the EPCs between FY 1997 and FY 2002, visit AHRQ's Web site at *http://www.ahrq.gov/clinic/epc#centers.*

3. Evidence-based Practice Centers (EPCs)

The EPCs prepare evidence reports and technology assessments on topics for which there is significant demand for information by health care providers, insurers, purchasers, health-related societies, and patient advocacy organizations. Such topics may include the prevention, diagnosis and/or treatment of particular clinical and behavioral conditions, use of alternative or complementary therapies, and appropriate use of commonly provided services, procedures, or technologies. Topics also may include issues related to the organization and financing of care. AHRQ widely disseminates the EPC evidence reports and technology assessments, both electronically and in print. The EPC evidence reports and technology assessments do not include clinical recommendations or recommendations on reimbursement and coverage policies.

4. Role/Responsibilities of Partners

Nominators of topics selected for development of an EPC evidence report or technology assessment assume the role of Partners to AHRQ and the EPCs, with defined roles and responsibilities. AHRQ places high value on these relationships, and plans to review Partners' past performance of these responsibilities at such time in subsequent years when AHRQ is considering whether to accept additional topics nominated by an organization. Specifically, Partners are expected to serve as resources to EPCs as they develop the evidence reports and technology assessments related to their nominated topic; serve as members of external peer reviewers of relevant draft evidence report and assessment; and commit to (a) timely translation of the EPC reports and assessments into their own quality improvement tools (*e.g.*, clinical practice guidelines, performance measures), educational programs, and reimbursement policies; and (b) dissemination of these derivative products to their membership. AHRQ also is interested in members' use of these derivative products and the products' impact on enhanced healthcare. AHRQ will look to the Partners to provide these use and impact data on products that are based on EPC evidence reports and technology assessments.

The AHRQ will review topic nominations and supporting information and determine final topics, seeking additional information as appropriate. AHRQ is very interested in receiving topic nominations from professional societies and organizations comprised of members of minority populations, as well as nomination of topics that have significant impact on the health status of women, children, ethnic and racial populations.

5. Topic Nomination and Selection Process

The processes that AHRQ employs to select topics nominated for analyses by the EPCs is described below. Section A addresses AHRQ's nomination process and selection criteria for clinical and behavioral topics. Section B addresses AHRQ's nomination process and selection criteria for organization and financing topics.

Section A: Clinical and Behavioral Topics

(a) Nomination Process for Clinical and Behavioral Topics

Nominations of clinical and behavioral topics for AHRQ evidence reports and technology assessments should focus on specific aspects of prevention, diagnosis, treatment and/or management of a particular condition, or on an individual procedure, treatment, or technoloy. Potential topics should be carefully defined and circumscribed so that the relevant published literature and other databases can be searched, evidence systematically reviewed, supplemental analyses performed, draft reports and assessments circulated for external peer review, and final evidence reports or technology assessments produced. Some reports and assessments can be completed within six months, if there is a small volume of literature to be systematically reviewed and analyzed. Other evidence reports and technolgy assessments may require up to 12 months for completion due to complexity of the topic, the volume of literature to be searched, abstracted, and analyzed, and completion of the external peer review process. Topics selected will not duplicate current and widely available research syntheses, unless new evidence is available that

suggests the need for revisions or updates.

For each topic, the nominating organization must provide the following information: (a) Rationale and supporting evidence on the clinical relevance and importance of the topic; and (b) plans for rapid translation of the evidence reports and technology assessments into clinical guidelines, performance measures, educational programs, or other strategies for strengthening the quality of health care services, or plans to inform development of reimbursement or coverage policies; (c) plans for dissemination of these derivative products to their membership; (d) process by which the nominating organization will measure the use of these products by their members, and impact of such use; and (e) process by which the organization will measure the impact of such use.

Specifically, nomination information should include:

- Defined condition and target population.
- Three to five very focused questions to be answered.
- Incidence or prevalence, and indication of the disease burden (*e.g.,* mortality, morbidity, functional impairment) in the U.S. general population or in subpopulations (*e.g.,* Medicare and Medicaid populations). For prevalence, the number of cases in the U.S. and the number of affected persons per 1,000 persons in the general U.S. population should be provided. For incidence, the number of new cases per 100,000 a year should be provided.
- Costs associated with the clinical or behavioral condition, including average reimbursed amounts for diagnostic and therapeutic interventions (*e.g.,* average U.S. costs and number of persons who receive care for diagnosis or treatment in a year, citing ICD9–CM and CPT codes, if possible).
- Impact potential of the evidence report or technology assessment to decrease health care costs or to improve health status or clinical outcomes.
- Availability of scientific data and bibliographies of studies on the topic.
- References to significant differences in practice patterns and/or results; alternative therapies and controversies.
- Plans of the nominating organization to incorporate the report into its managerial or policy decision making (*i.e.,* rapid translation of the report or assessment into derivative products such as clinical practice guidelines or other quality improvement tools, or to inform reimbursement or coverage policies about a particular technology or service).
- Plans of the nominating organization for dissemination of these derivative products to its membership.
- Process by which the nominating organization will measure members' use of the derivative products.
- Process by which the nominating organization will measure the impact of such use on clinical practice.

(b) Selection Criteria for Clinical and Behavioral Topics

Factors that will be considered in the selection of clinical and behavioral topics for AHRQ evidence report and technology assessment topics include: (1) High incidence or prevalence in the general population and in special populations, including women, racial and ethnic minorities, pediatric and elderly populations, and those of low socioeconomic status; (2) significance for the needs of the Medicare, Medicaid and other Federal health programs; (3) high costs associated with a condition, procedure, treatment, or technology, whether due to the number of people needing care, high unit cost of care, or high indirect costs; (4) controversy or uncertainty about the effectiveness or relative effectiveness of available clinical strategies or technologies; (5) impact potential for informing and improving patient or provider decision making; (6) impact potential for reducing clinically significant variations in the prevention, diagnosis, treatment, or management of a disease or condition, or in the use of a procedure or technology, or in the health outcomes achieved; (7) availability of scientific data to support the systematic review and analysis of the topic; (8) submission of nominating organization's plan to incorporate the report into its managerial or policy decision making, as defined above; (9) submission of nominating organization's plan to disseminate derivative products to its members; and (10) submission of nominating organization's plan to measure members' use of these products, and the resultant impact of these products on clinical practice.

Section B: Organization and Financing Topics

(a) Nomination Process for Organization and Financing Topics

Nominations of organization and financing topics for AHRQ evidence reports should focus on specific aspects of health care organization and finance. Topics should be carefully defined and circumscribed so that relevant databases may be searched, the evidence systematically reviewed, supplemental analyses performed, draft reports circulated for external peer review, and final evidence reports produced. Reports can be completed within six months if there is a small volume of literature for systematic review and analysis. Some evidence reports may require up to 12 months for completion due to the complexity of the topic and the volume of literature to be searched, abstracted, and analyzed. Topics selected will not duplicate current and widely available research syntheses, unless new evidence is available that suggests the need for revisions or updates.

For each topics, nominators should provide a rationale and supporting evidence on the importance and relevance of the topic. Nominators must also state their plans for use of the evidence report and indicate how the report could be used by public and private decision makers. Nomination information should include:

- Defined organizational/financial arrangement or structure impacting quality, outcomes, cost, access or use.
- Three to five focused questions to be answered.
- If appropriate, description of how the organizational/financial arrangement or structure is particularly relevant to delivery of care for specific vulnerable populations (*e.g.,* children, persons with chronic disease) or certain communities (*e.g.,* rural markets)
- Costs potentially affected by the organizational/financial arrangement, to the extent they can be quantified.
- Impact potential of the evidence report to decrease health care costs or to improve health status or outcomes.
- Availability of scientific and/or administrative data and bibliographies of studies on the topic.
- References to significant variation in delivery and financing patterns and/or results, and related controversies.
- Nominator's plan for use of an evidence report on this topic.
- Nominator's plan for measuring the impact of the report on organizational, financial, or delivery practices.

(b) Selection Criteria for Organization and Financing Topics

Factors that will be considered in the selection of topics related to the organization and financing of care include the following: (1) uncertainty about the impact of the subject organizational or financing strategy; (2) potential for the subject organizational or financing strategy or the proposed research synthesis to significantly impact aggregate health care costs; (3) policy-relevant to Medicare, Medicaid, and/or other Federal and State health programs; (4) relevant to vulnerable

populations, including racial and ethnic minorities, and particular communities, such as rural markets; (5) available scientific data to support systematic review and analysis of the topic; (6) plans of the nominating organization to incorporate the report into its managerial or policy decision-making; and (7) plans by the nominating organization to measure the impact of the report on practice.

Dated: January 15, 2003.

Carolyn M. Clancy,

Acting Director.

[FR Doc. 03–1913 Filed 1–27–03; 8:45 am]

BILLING CODE 4160–90–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Study Section Meetings—Change of Location

With this notice, the Agency for Healthcare Research and Quality informs the public of the change of location for two meetings. The original notice of these meetings was published in the **Federal Register** on January 7, 2003, Volume 68, Number 4, Page 785.

Below are the change of location of two meetings highlighted in bold.

- *Name of Subcommittee:* Health Systems Research.

Date: February 24–25, 2003, (Open from 6 p.m. to 6:15 p.m. on February 24 and closed for remainder of the meeting).

Place: AT–Doubletree Hotel (for both days), 1750 Rockville Pike, Conference Room TBD, Rockville, Maryland 20852.

- *Name of Subcommittee:* Health Care Quality and Effectiveness Research.

Date: February 26–27, 2003, (Open from 7 p.m. to 7:15 p.m. on February 26 and closed for remainder of the meeting).

Place: AT–Doubletree Hotel (for both days), 1750 Rockville Pike, Conference Room TBD, Rockville, Maryland 20852.

Agenda items for these meetings are subject to change as priorities dictate.

Dated: January 17, 2003.

Carolyn M. Clancy,

Acting Director.

[FR Doc. 03–1912 Filed 1–27–03; 8:45 am]

BILLING CODE 4160–90–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[Program Announcement: 03039]

Cooperative Agreement Training, Education, and Materials Development Regarding Terrorism Acts; Notice of Availability of Funds

A. Authority and Catalog of Federal Domestic Assistance Number

This program is authorized under section 301(a) and 317(a) of the Public Health Service Act, 42 U.S.C. sections 241(a) and 247b(a), as amended. The Catalog of Federal Domestic Assistance number is 93.283.

B. Purpose

The Department of Health and Human Services, Centers for Disease Control and Prevention (CDC) announces the availability of fiscal year (FY) 2003 funds for a cooperative agreement for development, implementation, and dissemination of effective terrorism preparedness and emergency response training and education programs. This program addresses the ''Healthy People 2010'' focus areas Immunization and Infectious Disease, Environmental Health, and Public Health Infrastructure.

The purpose of the program is to enhance the national security of the United States by improving the flow of timely and accurate information to the American general public. This will be accomplished by creating and maintaining a national training program for local community based organizations (CBOs) to develop their capacity to deliver effective terrorism preparedness education.

Measurable outcomes of the program will be in alignment with one or more of the following performance goals: help the American public to prepare for the unexpected; and reduce stress and make the public feel at ease should another emergency arise.

C. Eligible Applicants

Applications may be submitted by national non-profit and faith-based organizations with experience providing training services nationwide.

Note: Title 2 of the United States Code section 1611 states that an organization described in section 501(c)(4) of the Internal Revenue Code that engages in lobbying activities is not eligible to receive Federal funds constituting an award, grant or loan.

D. Funding

Availability of Funds

Approximately $1,000,000 is available in FY 2003, to fund one award. It is expected that the award will begin on or about March 30, 2003 and will be made for a 12-month budget period within a project period of up to five years. Funding estimates may change.

Continuation awards within an approved project period will be made on the basis of satisfactory progress as evidenced by required reports and the availability of funds.

Use of Funds

Funds may not be used to provide for direct patient medical care (*e.g.*, ongoing medical management, medications, *etc.*)

Recipient Financial Participation

Matching funds are not required for this program.

E. Program Requirements

In a cooperative agreement, CDC and the recipient of Federal funds share roles and responsibilities. In conducting activities to achieve the purpose of this program, the recipient will be responsible for the activities listed in 1. Recipient Activities, and CDC will be responsible for the activities listed in 2. CDC Activities.

1. Recipient Activities

a. Terrorism Preparedness Training and Education: Develop specific, measurable, and time-phased objectives for the execution of terrorism preparedness and emergency response training and education programs.

b. Develop Terrorism Preparedness Training and Education Programs: Collaborate with CDC to develop terrorism preparedness and emergency response training programs and material based on up-to-date information that is scientifically relevant and substantiated by valid behavioral science theory or empirical research.

c. Implement Terrorism Preparedness and Emergency Response Training and Education Programs: Provide training and technical assistance to local CBOs on conducting effective terrorism preparedness and emergency response education interventions.

d. Support collaboration with CBOs and other local providers to implement effective terrorism preparedness and emergency response education interventions. Terrorism preparedness and emergency response activities should be appropriate to the experience and resources of the affiliate and consistent with the unmet needs and priorities outlined in the state and local

health department's comprehensive terrorism preparedness and emergency response community planning process.

e. Develop collaborative relationships and linkages with behavioral and social scientists, national and local non-governmental organizations, state and local health departments, and other individuals and organizations that can assist in the accomplishment of the purpose of this cooperative agreement.

f. Evaluate Terrorism Preparedness and Emergency Response Training and Education Programs: Develop and implement an evaluation plan that describes how the accomplishment of the program objective at the national and local levels will be measured. The plan must include (a) a description of methods for monitoring program delivery; and (b) methods to measure outcome objectives for program improvement.

g. Conduct formative and summative evaluation as part of the instructional development process when designing program materials.

h. Design and implement systems to ensure training and education program quality.

i. Conduct process evaluation annually on program implementation and outcome evaluation on selected training and education programs periodically.

2. CDC Activities

a. Office of Terrorism Preparedness and Response (OPTR) shall provide consultation and technical assistance in the planning, development, implementation, and evaluation of program activities (*i.e.* training materials, identification and community-based organizations).

b. Depending on requirements, CDC Centers, Institutes, and Offices (CIOs), in close collaboration with OTPR, will provide up-to-date scientific information on the risk factors for terrorism preparedness, prevention measures, scientific research on behavioral intervention, and program strategies for terrorism preparedness. The CIOs include: The Agency for Toxic Substances and Disease Registry (ATSDR), the National Center for Environmental Health (NCEH), The National Center for Infectious Diseases (NCID), the National Immunization Program (NIP), The Public Health Practice Program Office (PHPPO), and The Epidemiology Program Office (EPO).

c. OTPR Senior Management will assist the grantee in collaborating with behavioral and social scientists, national and local non-governmental organizations, State and local health departments, community planning groups, other federally supported terrorism preparedness programs, and organizations that can assist the grantee in the accomplishment of the purpose of this cooperative agreement.

d. OTPR Senior Staff will facilitate the adoption and adaptation of effective education interventions and program models through meetings, workshops, conferences, newsletters, and communication with the project officer.

e. OTPR Senior Staff will provide program descriptions from research synthesis, scientific review, program feasibility activities, and CDC Scientific panels to be used in the development of terrorism preparedness and emergency response training and education programs.

f. OTPR Senior Staff will assist in the development of terrorism preparedness and emergency response training programs and materials based on empirical data on intervention effectiveness.

g. OTPR Senior Staff will assist the grantee in the dissemination of new programs by providing access to CDC partners in terrorism preparedness and emergency response.

F. Content

Letter of Intent (LOI)

A LOI is not required for this program.

Application

The program announcement title and number must appear in the application. Use the information in the Program Requirements, Other Requirements, and Evaluation Criteria sections to develop the application content. Your application will be evaluated on the criteria listed, so it is important to follow them in laying out your program plan. The narrative should be no more than 25 pages, double-spaced, printed on one side, with one-inch margins, and unreduced 12-point font.

The narrative should consist of, at a minimum, a Plan, Objectives, Methods, Evaluation and Budget.

G. Submission and Deadline

Application Forms

Submit the signed original and two copies of PHS form 5161. Forms are available at the following Internet address: *www.cdc.gov/od/pgo/forminfo.htm*

If you do not have access to the Internet, or if you have difficulty accessing the forms on-line, you may contact the CDC Procurement and Grants Office Technical Information Management Section (PGO–TIM) at: 770–488–2700. Application forms can be mailed to you.

Submission Date, Time, and Address

The application must be received by 4 p.m. Eastern Time March 14, 2003. Submit the application to: Technical Information Management–PA03039, CDC Procurement and Grants Office, 2920 Brandywine Road, Atlanta, GA 30341–4146.

Applications may not be submitted electronically.

CDC Acknowledgement of Application Receipt

A postcard will be mailed by PGO–TIM, notifying you that CDC has received your application.

Deadline

Applications will be considered as meeting the deadline if they are received before 4 p.m. Eastern Time on the deadline date. Any applicant who sends their application by the United States Postal Service or commercial delivery services must ensure that the carrier will be able to guarantee delivery of the application by the closing date and time. If an application is received after closing due to (1) carrier error, when the carrier accepted the package with a guarantee for delivery by the closing date and time, or (2) significant weather delays or natural disasters, CDC will upon receipt of proper documentation, consider the application as having been received by the deadline.

Any application that does not meet the above criteria will not be eligible for competition, and will be discarded. The applicant will be notified of their failure to meet the submission requirements.

H. Evaluation Criteria

Applicants are required to provide measures of effectiveness that will demonstrate the accomplishment of the various identified objectives of the cooperative agreement. Measures of effectiveness must relate to the performance goals stated in the purpose section of this announcement. Measures must be objective and quantitative and must measure the intended outcome. These measures of effectiveness must be submitted with the application and will be an element of evaluation.

An independent review group appointed by CDC will evaluate each application against the following criteria:

1. Technical Approach (30 Points)

The extent to which the application addresses:

a. An overall design strategy, including measurable time lines.

b. The relationship between activities and objectives.

c. Description of the management and analysis of data collected for meeting objectives.

2. Ability to Carry Out the Project (30 Points)

The extent to which the applicant provides evidence of their ability to carry out the proposed activity or project and the extent to which the applicant documents the demonstrated capability to achieve the purpose of this project.

3. Understanding of the Need or Problem (20 Points)

The extent to which the applicant demonstrates a clear, concise understanding of the need or problem to be addressed.

a. Extent to which the applicant specifically includes a description of the public health importance of the planned activities to be undertaken.

b. Extent to which the applicant provides a realistic presentation of the proposed project.

4. Personnel (10 Points)

The extent to which professional personnel involved in this activity or project are qualified, including evidence of prior experience similar to this activity or project. (Complete C.V. should be provided for professional and senior administrative staff; relevant training and experience should be highlighted). If a position is vacant, a position description and complete description of required qualifications for that position are to be included in the application along with a specific plan (including time line) for hiring.

5. Management Plan (10 Points)

The extent to which the applicant provides a description of the systems and the procedures that will be used to manage the progress, budget and operations of the activity or project.

6. Budget (Not Scored)

Extent to which the budget is reasonable, clearly justified, and consistent with the intended use of cooperative agreement funds.

I. Other Requirements

Technical Reporting Requirements

Provide CDC with the original plus two copies of:

1. Interim progress report, no less than 90 days before the end of the budget period. The progress report will serve as your non-competing continuation application, and must contain the following elements:

a. Current Budget Period Activities Objectives. Describe quantified progress in achieving objectives, as well as relevant evaluation findings, changes or adjustments in objectives resulting from evaluation findings, and reasons for not attaining an objective.

b. Current Budget Period Financial Progress.

c. New Budget Period Program Proposed Activity Objectives.

d. Detailed Line-Item Budget and Justification.

e. Additional Requested Information.

2. Financial status report, no more than 90 days after the end of the budget period.

3. Final financial and performance reports, no more than 90 days after the end of the project period. Send all reports to the Grants Management Specialist identified in the ''Where to Obtain Additional Information'' section of this announcement.

Additional Requirements

The following additional requirements are applicable to this program. For a complete description of each, see Attachment I of the program announcement as posted on the CDC Web site.

AR–1 Human Subjects Requirements
AR–7 Executive Order 12372 Review
AR–8 Public Health System Reporting Requirements
AR–9 Paperwork Reduction Act Requirements
AR–10 Smoke-Free Workplace Requirements
AR–11 Healthy People 2010
AR–12 Lobbying Restrictions
AR–13 Prohibition on Use of CDC Funds for Certain Gun Control Activities
AR–14 Accounting System Requirements
AR–15 Proof of Non-Profit Status

J. Where To Obtain Additional Information

This and other CDC announcements, the necessary applications, and associated forms can be found on the CDC Web site, Internet address: *http://www.cdc.gov.* Click on ''Funding'' then ''Grants and Cooperative Agreements''.

For general questions about this announcement, contact: Technical Information Management, CDC Procurement and Grants Office, 2920 Brandywine Rd, Room 3000, Atlanta, GA 30341–4146, Telephone: 770–488–2700.

For business management and budget assistance, contact: Sharon Robertson, Grants Management Specialist, Procurement and Grants Office, Centers for Disease Control and Prevention, 2920 Brandywine Road, Room 3000, Atlanta, GA 30341–4146, Telephone: 770–488–2748, E-mail: *sqr2@cdc.gov.*

For program technical assistance, contact: Amy Loy, Office of Terrorism Preparedness and Response, Centers for Disease Control and Prevention, 1600 Clifton Road, Atlanta, GA 30333, Telephone: 404–639–7855, E-mail: *anl6@cdc.gov.*

Dated: January 22, 2003.

Sandra R. Manning,

CGFM Director, Procurement and Grants Office, Centers for Disease Control and Prevention.

[FR Doc. 03–1824 Filed 1–27–03; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Healthcare Infection Control Practices Advisory Committee (HICPAC): Meeting

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces the following meeting.

Name: Healthcare Infection Control Practices Advisory Committee.

Times and Dates: 8:30 a.m.–5 p.m., February 24, 2003; 8:30 a.m.–4 p.m., February 25, 2003.

Place: Swissotel, 3391 Peachtree Road, NE, Atlanta, Georgia 30333.

Status: Open to the public, limited only by the space available.

Purpose: The Committee is charged with providing advice and guidance to the Secretary, HHS, the Director, CDC, the Director, National Center for Infectious Diseases (NCID), and the Director, Division of Healthcare Quality Promotion; NCID, regarding (1) the practice of hospital infection strategies for surveillance, prevention, and control of healthcare-associated infections (*e.g.*, nosocomial infections), antimicrobial resistance, and related events in settings where healthcare is provided; and (2) periodic updating of guidelines and other policy statements regarding prevention of healthcare-associated infections and healthcare-related conditions.

Matters To Be Discussed: Agenda items will include a review of the Draft Guideline for Preventing Transmission of Infectious Agents in Healthcare Settings (formerly Guideline for Isolation Precautions in Hospitals); the Draft Guideline for Disinfection and Sterilization in Healthcare Settings; the Draft Guideline for Prevention of Healthcare-associated Pneumonia; infection control issues related to smallpox and vaccinia; injection safety in ambulatory healthcare settings; and updates on CDC activities of interest to the committee.

Agenda items are subject to change as priorities dictate.

Contact Person for More Information: Michele L. Pearson, M.D., Executive Secretary, HICPAC, Division of Healthcare Quality Promotion, NCID, CDC, 1600 Clifton Road, NE, M/S A–07, Atlanta, Georgia 30333, telephone 404/498–1182.

The Director, Management Analysis and Services Office, has been delegated the authority to sign Federal Register notices pertaining to announcements of meetings and other committee management activities, for both the Centers for Disease Control and Prevention and the Agency for Toxic Substances and Disease Registry.

Dated: January 22, 2003.

Alvin Hall,

Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 03–1825 Filed 1–27–03; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Interagency Committee on Smoking and Health: Meeting

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces the following committee meeting:

Name: Interagency Committee on Smoking and Health (ICSH).

Date and Time: February 11, 2003, 1 p.m.—4 p.m.

Place: Department of Health and Human Services, Hubert H. Humphrey Building, Auditorium, Room 800, 200 Independence Avenue, SW, Washington, DC 20201.

Status: Open to the public, limited only by the space available. Those who wish to attend are encouraged to register with the contact person listed below. If you will require a sign language interpretator, or have other special needs, please notify the contact person by 4:30 E.S.T. on February 5, 2003.

Purpose: The Interagency Committee on Smoking and Health advises the Secretary, Health and Human Services, and the Assistant Secretary for Health in the (a) coordination of all research and education programs and other activities within the Department and with other federal, state, local and private agencies and (b) establishment and maintenance of liaison with appropriate private entities, federal agencies, and state and local public health agencies with respect to smoking and health activities.

Matters to be Discussed: The agenda will focus on the National Action Plan for Tobacco Cessation drafted by the Cessation Subcommittee. During the meeting, the action plan will be presented, debated and voted on by the ICSH. At a future date the Plan will be presented to the Secretary of Health and Human Services.

Contact Person for More Information: Substantive program information as well as summaries of the meeting and roster of committee members may be obtained from the Internet at *http://www.cdc.gov/tobacco* in mid-March or from Ms. Monica L. Swann, Program Specialist, Office on Smoking and Health, 200 Independence Avenue, SW, Suite 317B, Washington, DC 20201, (202) 205–8500.

The Director, Management Analysis and Services Office, has been delegated the authority to sign Federal Register notices pertaining to announcements of meetings and other committee management activities, for both the Centers for Disease Control and Prevention and the Agency for Toxic Substances and Disease Registry.

Dated: January 22, 2003.

Alvin Hall,

Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 03–1823 Filed 1–27–03; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. 02D–0526]

Draft Guidance for Industry on Drug Product: Chemistry, Manufacturing, and Controls Information; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing the availability of a draft guidance for industry entitled ''Drug Product: Chemistry, Manufacturing, and Controls Information.'' This draft guidance provides recommendations on the chemistry, manufacturing, and controls (CMC) information for drug products that should be submitted in original new drug applications (NDAs) and abbreviated new drug applications (ANDAs). The draft guidance is structured to facilitate the preparation of applications submitted in Common Technical Document (CTD) format.

DATES: Submit written or electronic comments on the draft guidance by June 27, 2003. General comments on agency guidance documents are welcome at any time.

ADDRESSES: Submit written requests for single copies of the draft guidance to the Division of Drug Information (HFD–240), Center for Drug Evaluation and Research, Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857. Send one self-addressed adhesive label to assist that office in processing your requests. Submit written comments on the draft guidance to the Dockets Management Branch (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852. Submit electronic comments to *http://www.fda.gov/dockets/ecomments*. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the draft guidance document.

FOR FURTHER INFORMATION CONTACT: Upinder Atwal, Center for Drug Evaluation and Research (HFD–623), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20852, 301–827–5848, or Christopher Joneckis, Center for Biologics Evaluation and Research (HFM–1), Food and Drug Administration, 8800 Rockville Pike, Bethesda, MD 20892, 301–435–5681.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a draft guidance for industry entitled ''Drug Product: Chemistry, Manufacturing, and Controls Information.'' This draft guidance addresses the information to be submitted in NDAs and ANDAs for drug products to ensure continued product quality (i.e., identity, strength, quality, purity, and potency). Recommendations are provided on the information that should be included for: (1) Description and composition of the drug product, (2) manufacture, (3) control of excipients, (4) control of drug products, (5) reference standards or materials, (6) container closure systems, and (7) stability. Information is also provided on the type of pharmaceutical development information that should be included in an NDA or ANDA. The draft guidance is structured to facilitate the preparation of applications submitted in CTD format. The draft guidance, when finalized, will replace the guidance entitled ''Submitting Documentation for the Manufacture and Controls for Drug Products'' (February 1987).

This guidance contains information collection provisions that are subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520). The collection of information in this guidance was approved under OMB control number 0910–0001.

This draft guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The draft guidance, when finalized, will represent the agency's current thinking on CMC information for drug products.

It does not create or confer any rights for or on any person and does not operate to bind FDA or the public. An alternative approach may be used if such approach satisfies the requirements of the applicable statutes and regulations.

II. Comments

Interested persons may submit to the Dockets Management Branch (see **ADDRESSES**) written or electronic comments regarding this document. Submit a single copy of electronic comments to *http://www.fda.gov/dockets/ecomments* or two hard copies of any written comments, except that individuals may submit one hard 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 Dockets Management Branch between 9 a.m. and 4 p.m., Monday through Friday.

III. Electronic Access

Persons with access to the Internet may obtain the document at *http://www.fda.gov/cder/guidance/index.htm*, *http://www.fda.gov/cber/guidelines.htm*, or *http://www.fda.gov/ohrms/dockets/default.htm*.

Dated: January 27, 2003.

Margaret M. Dotzel,

Assistant Commissioner for Policy.

[FR Doc. 03–1919 Filed 1–27–03; 8:45 am]

BILLING CODE 4160–01–S

DEPARTMENT OF THE INTERIOR

Office of the Secretary

Privacy Act of 1974: As Amended; Revision to an Existing System of Records

AGENCY: Office of the Secretary, Department of the Interior.

ACTION: Proposed revisions to an existing system of records.

SUMMARY: Under the Privacy Act of 1974, as amended (5 U.S.C. 552a), the Department of the Interior is issuing public notice of its intent to modify an existing Privacy Act system of records notice managed by the Office of the Secretary entitled the ''Electronic Email Archive System (EEAS)'', Interior—OS–10 (67 FR 46202–46203, dated July 12, 2002). The revisions will update the ''Categories of individuals covered by the system'' section.

EFFECTIVE DATE: These actions will be effective January 28, 2003.

FOR FURTHER INFORMATION CONTACT: For more information on the EEAS system and its requirements, please contact Regina Lawrence, Office of the Chief Information Officer, Department of the Interior at 202–208–5413, or mail at MS–5312–MIB, 1849 C St. NW., Washington, DC 20240.

SUPPLEMENTARY INFORMATION: In this notice, the Department of the Interior is proposing to add additional Departmental bureaus/offices that will be participating in the EEAS to the ''Categories of individuals covered by the system'' section. These additional bureaus/offices are the Office of Surface Mining, the Bureau of Reclamation, and the National Business Center. These bureaus/offices are being added because they may also send or receive email with information related to Indian Trust programs. The EEAS was developed as a way to respond to information requests from the Court in the *Cobell et al.* v. *Norton, et al.*, Federal District Court Case No. 1:96CV01285 litigation.

Thus, the Department of the Interior proposes to amend EEAS, Interior—OS–10 to read as follows:

Dated: January 23, 2003.

Marilyn A. Legnini,

Departmental Privacy Act Officer.

INTERIOR/OS–10

SYSTEM NAME:

Electronic Email Archive System (EEAS).

SECURITY CLASSIFICATION:

Sensitive, but unclassified.

SYSTEM LOCATION:

The records of this system are located at a digital safe site at a location managed by the contractor for the Department of the Interior. Only information maintained at this site by the contractor is considered a Privacy Act system of records covered by this notice.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

The system contains information on individuals who send and receive electronic messages using Internet email and interoffice email from and to those Departmental bureaus/offices involved with Indian Trust programs, and those individuals who are referred to in the electronic messages. These bureaus/offices are as follows: Office of the Solicitor; Bureau of Indian Affairs; Office of the Special Trustee for American Indians; Office of the Assistant Secretary—Indian Affairs; Bureau of Land Management; Office of the Assistant Secretary—Policy, Management, and Budget; Office of Hearings and Appeals; Office of Historical Trust Accounting; Office of the Secretary; the Minerals Management Service; the United States Geological Survey; the National Park Service; and the U.S. Fish and Wildlife Service. The following bureau/offices are being added to the EEAS because the Court is concerned that they may send or receive email containing individual Indian Trust related information: the Office of Surface Mining; the Bureau of Reclamation; and the National Business Center.

CATEGORIES OF RECORDS IN THE SYSTEM:

Records include information from Internet email and interoffice email, including address of sender and receiver(s), subject, date sent or received, text of the message, name of attachment, attachment text, and certification status. The name and email address of the sender and receiver are captured along with the bcc, cc, subject line, and text of the message.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 301, 43 CFR part 1455, and 40 CFR part 1441.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

The system's main purpose is to respond to requests from the federal district court in *Cobell* v. *Norton* regarding information about individual Indian Trust programs that is embodied in email communication.

Disclosures outside the Department of the Interior can be made to:

(a) Contractors who service and maintain the system for the Department, ensuring that all provisions of the Privacy Act, and all other applicable laws, regulations, and policies relating to contracting and record security are met.

(b) Another Federal agency to enable that agency to respond to an inquiry by the individual to whom the record pertains.

(c)(1) To any of the following entities or individuals.

(A) The Department of Justice (DOJ), or

(B) To a court, adjudicative or other administrative body, or

(C) To a party in litigation before a court or adjudicative or administrative body, or

(D) The Department or any component of the Department, or

(E) Any Department employee acting in his or her official capacity, or

(F) Any Departmental employee acting in his or her individual capacity if the Department or the DOJ has agreed to represent that employee or pay for private representation of the employee,

(2) When:

(A) One of the following is a party to the proceeding or has an interest in the proceeding:

(i) The Department or any component of the Department;

(ii) Any Department employee acting in his or her official capacity;

(iii) Any Departmental employee acting in his or her individual capacity if the Department or the DOJ has agreed to represent that employee or pay for private representation of the employee;

(iv) The United States, when the DOJ determines that the Department is likely to be affected by the proceeding; and

(B) The Department deems the disclosure to be:

(i) Relevant and necessary to the proceeding; and

(ii) Compatible with the purposes for which the records were compiled.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Information in this system of records is maintained in electronic format on a system hard drive.

RETRIEVABILITY:

This specific system has the capability of performing searches through email archive information identified in the ''Category of records'' section above using any word or number criteria. This capability makes it unique from other email archive systems that are maintained by Interior bureaus/offices, and therefore, this system becomes subject to Privacy Act requirements.

SAFEGUARDS:

The contractor maintaining this system must follow the requirements under 5 U.S.C. 552a(e)(10) and 43 CFR 2.51 for security standards. A security plan was developed to prevent unauthorized access to the system. The plan addresses application security, administration/user security, and application agreements. Access to the system is limited to authorized personnel whose official duties require such access. The EEAS system will be maintained at the Government contractor's facility at a secured data center.

RETENTION AND DISPOSAL:

Records in this system will be retained indefinitely pending completion of *Cobell et al.* v. *Norton*, *et al.*, U.S.D.C. D.C., No. 1:96CV01285 or until the Court orders the Department to retain/dispose of these records differently.

SYSTEM MANAGER(S) AND ADDRESS:

The Technology Services Division, Administrative Operations Directorate, National Business Center, Department of the Interior, MS–1540–MIB, 1849 C St. NW., Washington, DC 20240.

NOTIFICATION PROCEDURES:

To determine whether your records are in this Privacy Act system of records, contact the Privacy Act Officer at the bureau/office from which your email message was sent or where it was received (see list of participating bureau/offices identified in the ''Categories of individuals'' section above). Interior bureaus/offices are listed at the Department of the Interior Web site at *http://www.doi.gov.* The request must meet the requirements of 43 CFR 2.60. Provide the following information with your request:

(a) Proof of your identity;

(b) List of all the names by which you have been known, such as maiden name or alias;

(c) Your Social Security Number;

(d) Your mailing address;

(e) Time period(s) that records pertaining to you may have been created or maintained, to the extent known by you (*See* 43 CFR 2.60(b)(3)); and

(f) Specific description or identification of the records you are requesting (including whether you are asking for a copy of all of your records or only a specific part of them), and the maximum amount of money that you are willing to pay for their copying (*See* 43 CFR 2.63(b)(4)).

RECORD ACCESS PROCEDURES:

To request access to records, follow procedures in the ''Notification procedure'' section above. The request must meet the requirements of 43 CFR 2.63. Provide with your request the same information identified in the ''Notification procedures'' sections.

CONTESTING RECORD PROCEDURES:

To request an amendment of a record, send requests in writing to the contacts identified in the ''Notification procedure'' section above. The request must meet the requirements of 43 CFR 2.71.

RECORDS SOURCE CATEGORIES:

Some information maintained in the system is collected from mag-tapes provided by Interior bureau/office email backup systems from those installations identified in the ''Categories of individuals'' section above. This information is downloaded onto a hard drive managed by the contractor and stored digitally. Information from Interior bureau/office e-mail servers will be captured in real time, transmitted electronically through secured networks, and captured and stored electronically into the EEAS.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

[FR Doc. 03–1891 Filed 1–27–03; 8:45 am]

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DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Endangered and Threatened Wildlife and Plants; 90-Day Finding for a Petition to List the Tri-State Area Flock of Trumpeter Swans as Threatened

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of 90-day petition finding.

SUMMARY: We, the Fish and Wildlife Service (Service), announce a 90-day finding for a petition to list the Tri-State Area flock of trumpeter swans (*Cygnus buccinator*) as an endangered or threatened species under the Endangered Species Act of 1973. We find that the petition does not provide substantial information indicating that this flock is a Distinct Population Segment (DPS) that may warrant listing. We will not be initiating a further status review in response to the petition. However, we ask the public to submit to us any new information that becomes available concerning the status of or threats to this flock of trumpeter swans. This information will help us monitor and manage this species.

DATES: The finding announced in this document was made on January 15, 2003. You may submit new information concerning this species for our consideration at any time.

ADDRESSES: Submit information, data, or comments concerning this petition to the Assistant Regional Director, Ecological Services, U.S. Fish and Wildlife Service, P.O. Box 25486, DFC, Denver, CO 80225–0486. The petition, finding, and supporting data are available for public inspection, by appointment, during normal business hours, at the above address, and on our website at: *http://www.r6.fws.gov/birds/trumpeterswan/.*

FOR FURTHER INFORMATION CONTACT: Chuck Davis, Endangered Species Listing Coordinator, at the above address, or by telephone at 303–236–7400, extension 235, or by email at *chuck_davis@fws.gov.*

SUPPLEMENTARY INFORMATION:

Background

Section 4(b)(3)(A) of the Endangered Species Act of 1973, as amended (Act) (16 U.S.C. 1531 *et seq.*), requires that we make a finding on whether a petition to list, delist, or reclassify a species presents substantial scientific or commercial information to demonstrate that the petitioned action may be warranted. This finding is to be based on all information available to us at the time we make the finding. To the maximum extent practicable, this finding is to be made within 90 days of our receipt of the petition, and the notice of the finding is to be published promptly in the **Federal Register**. Our standard for substantial information within the Code of Federal Regulations (CFR) with regard to a 90-day petition finding is ''that amount of information that would lead a reasonable person to believe that the measure proposed in the petition may be warranted'' (50 CFR 424.14(b)(1)). If we find that substantial information was presented, we are required to promptly commence a review of the status of the involved species, if one has not already been initiated under our internal candidate assessment process.

In 1989, we were petitioned to list a portion of the trumpeter swans in North America (Rocky Mountain Population (RMP), see below) as threatened. However, the petition presented information that we deemed insufficient to warrant proceeding with a status review (55 FR 17646–17648; April 16, 1990).

On August 25, 2000, we received a petition to list the Greater Yellowstone (Tri-State) breeding population of the trumpeter swan as threatened or endangered. The petitioners, the Biodiversity Legal Foundation and Fund for Animals, assert that the Tri-State Area flock meets the definition of a DPS, as defined in our policy published February 7, 1996 (61 FR 4722), and, therefore, warrants listing because of its low population numbers and other threats, including the allowed take of trumpeter swans during the hunting seasons in Utah and Nevada.

On September 22, 2000, we notified the petitioners that our Listing Priority Guidance, published in the **Federal Register** (64 FR 57114) on October 22, 1999, designated the processing of new listing petitions as a Priority 4 activity (*i.e.*, of lower priority than processing emergency listings, processing determinations on proposed species, and resolving the status of candidate species). We further informed the petitioners that we consider the Tri-State Area trumpeter swan flock as a portion of the RMP, which has had an increasing number of swans since the 1960s. Therefore, we did not find a compelling reason to consider the petition under emergency listing criteria, and no funds were available to proceed with an administrative finding at that time.

On October 25, 2000, the petitioners and the Utah Environmental Congress, Margaret Pettis, and Mack P. Bray, filed a formal complaint in Federal District Court for the District of Columbia (*Fund for Animals* v. *Clark,* 00–CV–02558) alleging that we violated the Act by failing to publish a 90-day finding for their petition. Plaintiffs also allege that the Service violated provisions of the MBTA, the National Environmental Policy Act (NEPA), and the Administrative Procedures Act by allowing implementation of a limited trumpeter swan hunting season in 2000. The case was settled on March 23, 2001, when we agreed to reevaluate our compliance with the MBTA and NEPA for the 2002 hunting season regulations.

On February 5, 2001, we received a 60-day notice of intent from Meyer and Glitzenstein, legal representatives for the petitioners, alleging that we had violated the Act by failing to make a finding as to whether the petition to list the Tri-State Area trumpeter swan flock presented substantial information indicating that listing may be warranted. We responded on April 4, 2001, reiterating that we would not be able to begin an evaluation of the petition until the work on the higher-priority activities was completed. On September 6, 2001, Meyer and Glitzenstein filed another 60-day notice alleging that we violated the Act by failing to make a 12-month finding within 1 year of the receipt of the trumpeter swan petition.

On October 3, 2001, plaintiffs were joined by the Humane Society of the United States in a new complaint alleging that our reevaluation of the swan hunting regulations was not adequate, and that we had violated the Act by failing to prepare a 90-day finding on the swan petition (*Fund for Animals et al.* v. *Norton*, 01–CV–2078 (RMU)).

On March 5, 2002, plaintiffs filed an amended complaint to include the allegation that we had violated the Act by failing to complete a 12-month finding on the swan petition. The case has been briefed and a decision is pending from the court.

Petitioners' Assertions

Petitioners assert that the Tri-State ''population segment'' of trumpeter swans, a group of largely non-migratory swans that breed and winter in the Greater Yellowstone area in and around Yellowstone National Park in Wyoming, Montana, and Idaho, qualifies as a listable entity under the Act in accordance with our DPS policy cited above. The petition asserts that the Tri-State segment is geographically and biologically distinct from other trumpeter swan groups in North America and the United States. The petitioners propose that the segment is discrete because it is separated by physical, physiological, ecological, behavioral, ''or other factors,'' and is separated by approximately 400 miles from any other significant breeding groups of this species. Petitioners also assert that the Tri-State Area flock is distinct from other swan flocks in Canada by reason of the international boundary and alleged differences in exploitation and management of this species between Canada and the United States.

Petitioners allege that the Tri-State Area flock has lost ''more than 30 percent of its adults in the past decades, and is in an imperiled situation.'' The petition recommends that we consider emergency listing of the petitioned DPS.

Distinct Population Segment Analysis

Under the Act, we must consider for listing any species, subspecies, or, for vertebrates, any DPS of these taxa, if sufficient information is present to indicate that such action may be warranted.

To implement the measures prescribed by the Act and its Congressional guidance, we developed policy that addresses the recognition of DPSs for potential listing actions (61 FR 4722; February 17, 1996). The policy allows for more refined application of the Act that reflects the biological needs of the taxon being considered and avoids the inclusion of entities that do not require its protective measures.

The Act's legislative history (Senate Report 96–151, 1st Session) indicates that Congress expects the Services (Fish and Wildlife Service and National Marine Fisheries Service) to use the DPS designation ''*sparingly and only when the biological evidence indicates that such action is warranted*'' (emphasis added).

The background information included with the publication of our final DPS policy indicates that any interpretation adopted for DPS determination should be consistent with the purposes of the Act (*i.e.*, ''*to provide a means whereby the ecosystems upon which endangered species and threatened species depend may be conserved, to provide a program for conservation of such endangered species and threatened species, and to*

take such steps as may be appropriate to achieve the purposes of the treaties and conventions set forth in subsection (a) of this section'' (emphasis added).

Under our DPS policy, we use two elements to assess whether a population segment under consideration for listing may be recognized as a DPS. The elements are: (1) The population segment's discreteness from the remainder of the taxon; and (2) the population segment's significance to the taxon to which it belongs. Both elements must be present for a segment to qualify as a DPS. When responding to a listing petition, we are required to use all information available to us at the time we make the finding. If we determine that a population segment being considered for listing represents a DPS, then the level of threat to the population segment is evaluated based on the five listing factors established by the Act to determine if listing it as either threatened or endangered is warranted. Those listing factors are: (1) The present or threatened destruction, modification, or curtailment of habitat or range; (2) overutilization for commercial, recreational, scientific, or educational purposes; (3) disease or predation; (4) the inadequacy of existing regulatory mechanisms; and, (5) other natural and manmade factors affecting its continued existence. Listing is warranted if one or more of those threats could lead to the extinction of the species throughout all or a significant portion of the range of the species in the foreseeable future.

Discreteness—A population segment of a vertebrate species may be considered discrete if it satisfies either one of the following two conditions: (1) It is markedly separated from other populations of the same taxon as a consequence of physical, physiological, ecological, or behavioral factors. Quantitative measures of genetic or morphological discontinuity may provide evidence of this separation, (2) It is delimited by international governmental boundaries within which differences in control of exploitation, management of habitat, conservation status, or regulatory mechanisms exist that are significant with regard to conservation of the taxon.

The petition asserts that the Tri-State segment of trumpeter swans is geographically and biologically distinct from other trumpeter swans in North America and the United States. The petitioners propose that the segment is discrete because it is separated by physical, physiological, ecological, behavioral, ''or other factors,'' and is separated by approximately 400 miles from any other significant breeding groups of this species. Petitioners also assert that the Tri-State Area flock is distinct from other swan flocks in Canada because of the presence of the international boundary and because of alleged differences in exploitation and management of this species between Canada and the United States. Below we discuss in detail the conditions for which we will consider a population to be discrete under the DPS policy as applied to the Tri-State Area flock.

(1) Is the Tri-State Area Flock Markedly Separated From Other Populations of the Same Taxon as a Consequence of Physical, Physiological, Ecological, or Behavioral Factors?

Historic range maps indicate that the trumpeter swan had a more contiguous distribution than exists today. As the species' range was restricted due to overexploitation and habitat loss, remnant groups of birds inhabited disjunct breeding areas. Although the exact time at which the present degree of separation occurred is unknown, we believe that it occurred during the peak of trade in swan skins in the mid- to late 1800s. Trumpeter swans have relatively long life spans; birds more than 24 years old have been recaptured in the wild (Kennard 1975). Hence, relatively few (perhaps 6 or 7) generations of trumpeter swans have elapsed since that time. Suzuki *et al.* (1981) state that only one immigrating individual per generation is necessary to maintain genetic continuity between spatially segregated groups of individuals within a species. Mills and Allendorf (1996) suggest a minimum range of 1 to 10 individuals per generation is needed to maintain gene flow between groups of animals. Limited monitoring studies have documented several individuals in non-natal nesting areas (Gale *et al.* 1987, Dubovsky and Cornely 2002) and one mixed-group (*i.e.*, Canadian/Tri-State) pairing (Shea and Drewien 1999). Further, the Interior Canada and Tri-State birds are spatially segregated only during the nesting season; they are sympatric (overlapping in range) during winter, when pairing usually occurs (Johnsgard 1978, Gale *et al.* 1987). For these reasons, we conclude it is unlikely that the Tri-State Area flock has become genetically distinct from the Interior Canada birds. Even if little or no movement of birds between flocks has occurred, there is no evidence that a sufficient amount of time has passed since the mid-1800s for morphology, behavior, and genetics of Tri-State birds to become distinctly different from those of other flocks.

Recently, the Service, in consultation with the Flyway Councils, divided trumpeter swans into three administrative populations on the basis of areas in which they nest. These populations are defined primarily for management purposes and not in recognition of reproductive isolation or genetic differentiation (Trost *et al.* 2000). In fact, one of the populations is derived exclusively from birds and eggs translocated from the other two populations.

The Pacific Coast Population (PCP) is comprised primarily of birds that nest in Alaska and winter along the west coast of Canada and the United States as far south as Oregon (Figure 1). Observations of a very limited number of marked birds from this group suggest that birds nesting in Alaska do not often migrate or winter east of British Columbia or the Pacific Coast States (Dubovsky and Cornely 2002).

The RMP is comprised of birds that nest east of the range of the PCP to areas just east of the western border of Saskatchewan and points south. Most birds in the RMP winter at the confluence of the borders of Montana, Idaho, and Wyoming (hereafter termed the ''Tri-State'' Area) (Subcommittee on Rocky Mountain Trumpeter Swans 1998).

The Interior Population (IP) is comprised of birds that nest east of the range of the RMP. The IP is the result of extensive restoration efforts, and is composed almost exclusively of PCP and RMP birds and eggs that were translocated to these eastern areas. Birds from the IP tend to winter primarily in areas near to or south of their nesting grounds (Dubovsky and Cornely 2002).

Of all the populations, the status of the RMP has been subject to the largest amount of debate over the years. The RMP is comprised primarily of two groups of birds: one that nests in Canada and the other that nests in the Tri-State Area. The latter group contained only about 70 birds in the early 1930s. These were erroneously thought to be the only free-ranging trumpeter swans in the world (Banko 1960). The birds nested primarily in Yellowstone National Park and the Centennial Valley area of Montana, and wintered in those areas and adjacent areas in Idaho (Banko 1960).

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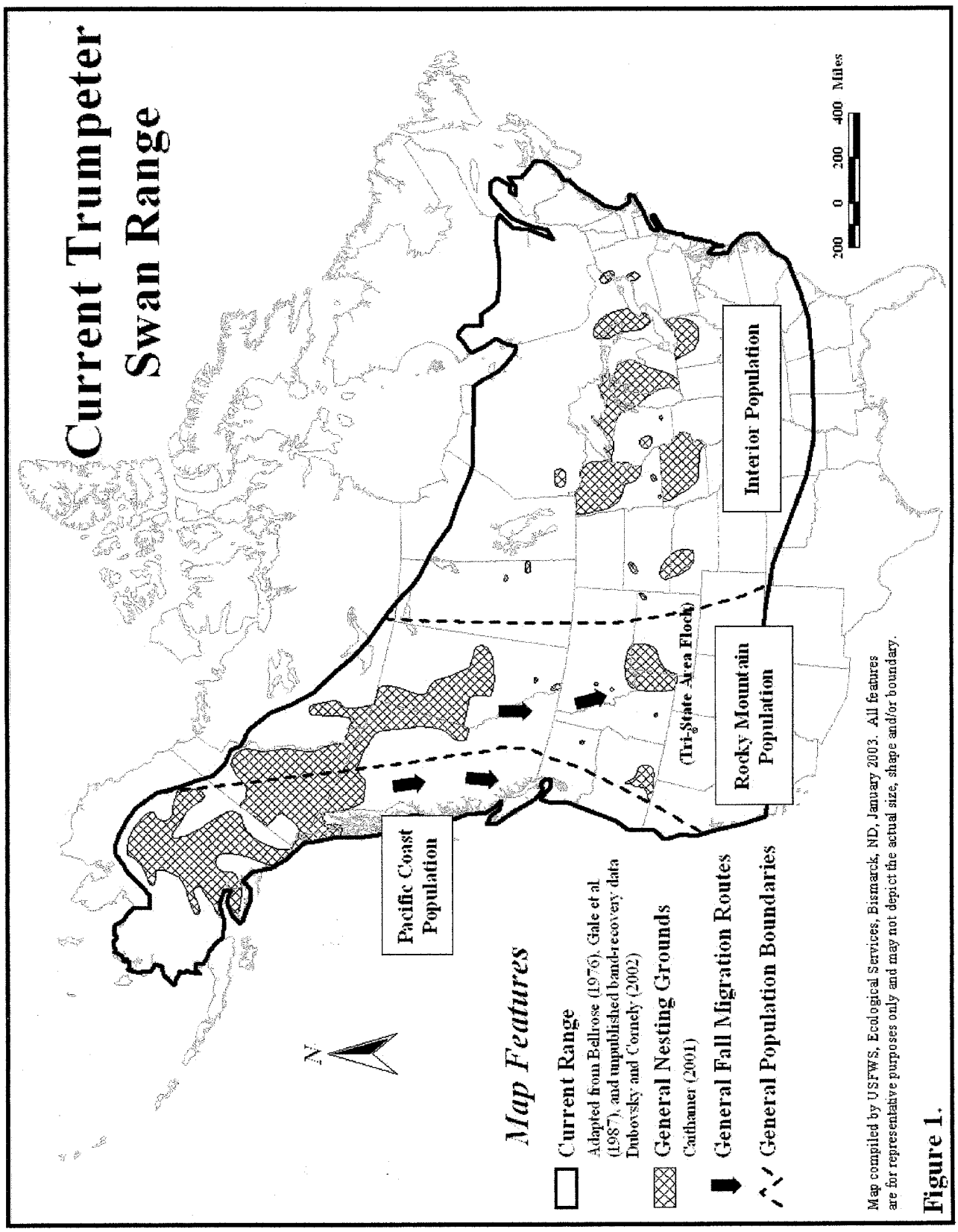

Figure 1.

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Our analysis of the trumpeter swan Tri-State segment indicates that these birds are derived from a remnant flock that survived the market hunting overexploitation of the species that occurred in North America prior to the protections of the MBTA in 1918. Some swans found refuge in the isolated and protected environs of Yellowstone National Park, high-elevation areas that have harsh winters and a short nesting season compared to lower elevations. Some people speculate that Tri-State swans are specially adapted to this marginal habitat. However, we have found no scientific evidence to support such a conclusion. No evidence indicates that the birds in this flock were isolated for periods of time sufficient for such adaptions to occur. Some have speculated that the swans that nested in the Tri-State Area once migrated elsewhere for the winter, but we know of no data to verify whether they were migratory or not prior to European settlement of the Tri-State Area (Gale *et al.* 1987, Dubovsky and Cornely 2002). Implementation of an artificial feeding program beginning in 1935 may have modified the swans' natural migratory behavior, but that also is conjecture (Dubovsky and Cornely 2002).

The petition alleges that the Tri-State Area flock is discrete from other portions of the North American trumpeter swan population in part because the Tri-State birds are separated from other breeding populations by approximately 400 miles. The petitioners assert that breeding pairs are not formed between the Tri-State birds and other swan populations.

There are no known physical, physiological, or behavioral differences between any of the trumpeter swan flocks in North America (Gale *et al.* 1987). Even if most of the Tri-State swans do not migrate to nesting grounds in Canada (which available data suggest) (Dubovsky and Cornely 2002), this behavior is not evolutionarily significant within the meaning of our DPS policy. Numerous flocks of geese and swans (including trumpeters) in the United States exhibit nonmigratory behavior because sufficient life requisites exist in the flocks' habitat throughout the year. Therefore, the fact that the birds in the Tri-State Area flock are not known to migrate long distances is not a unique behavioral trait within the meaning of the DPS policy.

The petitioners allege, based on neck-collar observations, that the Canadian- and United States-nesting birds are reproductively isolated because birds have not been seen nesting on their non-natal nesting grounds. However, although many swans have been marked over the years, observations of marked swans are of a limited value in establishing the reproductive isolation of the Tri-State Area flock. Many observations of marked swans were of those that had been trapped and translocated. It is not appropriate to use observations of these birds to make inferences about natural movements and pairing behavior of free-flying wild trumpeter swans. Further, many swans are marked but never seen again, or are seen only during the first few years after marking (*e.g.*, Gale *et al.* 1987:286, Shea and Drewien 1999). Given that swans are long-lived, much of the neck-collar data may reflect only a small fraction of these birds' reproductive lifetime and thus is not indicative of all of an individual bird's movement patterns. Trumpeter swans also inhabit many remote areas that are not amenable to direct observations of the birds. Therefore, it is plausible that some marked birds may nest in remote areas that are not their natal nesting grounds. Lastly, one observation of a mixed-group (Canadian/Tri-State) pairing has been documented (Shea and Drewien 1999); mark-recovery information indicates two Tri-State Area nesting birds were sighted in Alberta (Dubovsky and Cornely 2002), and two birds marked in Grande Prairie summered in the Tri-State Area (Gale *et al.* 1987). These instances suggest that some reproductive intermingling of the two flocks may be occurring, that gene flow is possible between the groups, and that sampling procedures may simply have been inadequate to detect much interchange to date. Therefore, we conclude that current information does not support the petitioner's allegations that the Tri-State Area flock is reproductively isolated.

Our DPS policy provides that quantitative measures of genetic or morphological discontinuity may provide evidence of discreteness. As discussed in detail below based on current trumpeter swan genetic information, we conclude that available information does not provide evidence of genetic discontinuity that would support the contention that the Tri-State Area flock is discrete.

(2) Is the Tri-State Area Flock Delimited by International Governmental Boundaries Within Which Differences in Control of Exploitation, Management of Habitat, Conservation Status, or Regulatory Mechanisms Exist That Are Significant With Regard to Conservation of the Taxon?

Under the DPS policy, we specifically look for differences in regulatory mechanisms between nations that are significant in light of section 4(a)(1)(D) of the Act (*e.g.*, whether inadequate regulatory mechanisms in one nation as compared to another may contribute to species endangerment), such that it would be consistent with the purposes of the Act to delineate a population based on a non-biological element. Simply stated, we look for regulatory differences between nations that are relevant to a listing decision and that would warrant separating populations of a taxon using international boundaries.

The petitioners allege that the Tri-State Area flock should be considered distinct from other trumpeter swan flocks in North America because of a difference in management and exploitation of the species in Canada. However, migratory waterfowl are managed under the auspices of international treaties, including the Migratory Bird Treaty with Canada which the MBTA implements, and highly structured international entities, such as the Flyway Councils. The goals of the Pacific Flyway Council concerning trumpeter swan management are international in scope (*i.e.*, the Council contains representatives from both Canada and the United States) and include encouraging growth of the Canadian flocks while rebuilding United States breeding flocks of trumpeter swans (Subcommittee on Rocky Mountain Trumpeter Swans 1998). Public education goals and research needs include the same tasks in both countries. The Province of Alberta has supported management actions in the United States, including implementation of a general swan season (U.S. Department of the Interior 2001).

With regard to habitat management, the United States and Canada protect breeding areas, conduct swan transplants, band or otherwise mark birds, and monitor population status. Establishment of annual sport-hunting regulations in both countries is completed in accordance with the Convention Between the United States and Great Britain (for Canada) for the Protection of Migratory Birds (1916 Treaty). Both countries also publish draft regulations that are subject to public review and comment. Neither country has a sport-hunting season specifically for trumpeter swans. Swans in both countries are protected by similar regulatory processes. Canada and the United States (Alaska) allow subsistence take of swans during the spring and summer. As discussed earlier in this document, the United States has established a limited quota for allowable take of trumpeter swans as part of the package of trumpeter swan conservation measures. All waterfowl hunting

regulations in both countries are subject to annual review and revision. Therefore, we find no significant differences in trumpeter swan management between Canada and the United States within the meaning of our DPS policy.

In Canada, the trumpeter swan was listed as a vulnerable species in 1978 (Mackay 1978), but the species was moved to the not-at-risk category after re-examination in 1996 (Committee on the Status of Endangered Wildlife in Canada 2002). The species is listed as a vulnerable species in Alberta (Government of Alberta 2002), which means that without management and protection, the species could become threatened or endangered *within the province* (emphasis added). However, management actions to enhance trumpeter swan abundance and distribution in Alberta are the same as those in the rest of Canada and the Pacific flyway, as discussed above.

Trumpeter swans and tundra swans are both large white birds with black bills; the two are extremely difficult to distinguish from each other at a distance. Both species can occur in the same area during some parts of the year. Since the 1960s we have sanctioned hunting of tundra swans (*Cygnus columbianus*) under the provisions of the Migratory Bird Treaty Act (MBTA). Prior to 1995, season lengths for tundra swans were quite long (approximately 100 days); the amount of area open to hunting was large (essentially the entire State of Utah and areas of high swan use in Nevada and Montana). Illegal harvest of trumpeter swans during tundra swan hunting seasons occurred, probably by accident resulting from misidentification. The degree of take was unknown because no monitoring of species-specific swan harvests was conducted.

The RMP has been increasing at an average annual rate of 4.6 percent since 1968. The low rate of expansion of trumpeter swans into new wintering areas is believed by managers to limit further improvement of the status of the species (Subcommittee on Rocky Mountain Trumpeter Swans 1998). The Pacific Flyway's subcommittee on Rocky Mountain Trumpeter Swans determined that translocation of trumpeter swans to new wintering locations was a possible means of expanding the wintering range of the swans. Some of the Subcommittee members from States with potentially suitable wintering areas for translocated birds would not agree to relocations unless tundra swan hunters who mistakenly shot a trumpeter swan during the general swan season were relieved of liability under the MBTA (U.S. Department of the Interior 2001).

Therefore, to enhance the potential for trumpeter swan range expansion and limit the likely but unknown amount of harvest of trumpeter swans, several modifications to swan seasons were implemented in 1995. First, the area open to swan hunting was greatly reduced, and in Utah (where most swans were harvested) the area was restricted to only portions of six counties in the northwest corner of the State. The season ending date was changed from late January to early December, thus reducing the season length by 40 percent, in order to reduce the likelihood of sport-hunting mortality for trumpeter swans that may migrate into the hunt areas when more-northerly wetlands in the Tri-State Area freeze. We included provisions for a limited take (quotas) of trumpeter swans in Utah (15 individuals) and Nevada (5 individuals) to protect hunters from criminal liability if they accidentally shoot a trumpeter swan, because it often is not possible for hunters to distinguish the two species from each other in the field. If the quota was reached in a particular state, all swan hunting would be closed in that State for the remainder of the season. Finally, monitoring of swan harvest was intensified to enhance detection of trumpeter swans taken during hunts. In 2000, the area open to swan hunting in Utah was reduced even further, and the quota was reduced to 10 individuals (U.S. Department of the Interior 2001). There is no indication that the harvest serves as a threat to the continued health of either the Rocky Mountain trumpeter swan population or the Tri-State Area flock (*see* Table 1) and, therefore, the take is not significant to the conservation of the taxon within the meaning of section 4(a)(1)(D) of the Act.

Although the available evidence does not demonstrate that the Tri-State flock is discrete under the DPS policy, this flock could potentially be considered to be physically separated to some degree from the rest of the RMP during the breeding season. Further, our DPS policy does not require absolute reproductive isolation as a prerequisite to recognizing a DPS. Therefore, we have taken the further step of considering the biological and ecological significance of the Tri-State Area flock in light of Congressional guidance that the authority to list DPSs be used ''sparingly'' while encouraging the conservation of genetic diversity. In carrying out this examination, we consider available scientific evidence of the discrete population segment's importance to the taxon to which it belongs.

Significance—Our DPS policy provides several examples of the types of information that may demonstrate the significance of a population segment to the remainder of its taxon, including: (1) Persistence of the discrete population segment in an ecological setting unusual or unique for the taxon; (2) evidence that the discrete population segment differs markedly from other population segments in its genetic characteristics; (3) evidence that the discrete population segment represents the only surviving natural occurrence of a taxon that may be more abundant elsewhere as an introduced population outside its historic range; and (4) evidence that loss of the discrete population segment would result in a significant gap in the range of the taxon. While significance is not necessarily limited to these examples, we began by considering each example with respect to the Tri-State Area flock.

(1) *Ecological setting*—The petitioners allege that the Tri-State Area flock is an important remnant population of trumpeter swans in the lower 48 States and, therefore, meets the significance criterion of the DPS policy. Tri-state swans utilize wetland habitats in the region that provide requisite feeding, resting, nesting and brood rearing habitats. Trumpeters breed in relatively small, shallow wetlands at a wide range of elevations from just above sea-level to montane areas in North America. The fact that trumpeter swans breed in suitable wetlands in a variety of geographically diverse settings does not suggest that the Tri-State Area flock is likely to represent a significant resource in terms of the overall welfare of the species. The higher elevation, montane wetlands appear to provide more marginal breeding habitat for swans because of the shorter nesting and brooding season compared to wetlands at lower elevations.

(2) *Genetic characteristics*—No evidence exists to indicate that the Tri-State swans differ markedly from other trumpeter swans genetically.

The Tri-State birds exhibit no morphological differences from other trumpeter swans in North America (Gale *et al.* 1987). Several studies have been conducted to investigate genetic similarities among different groups of trumpeter swans nesting in North America (Barrett and Vyse 1982, Marsolais and White 1997, Pelizza, unpub. ms.). However, to date only one of those studies has been accepted for publication in a peer-reviewed professional journal. Barrett and Vyse (1982) compared blood proteins among

swans from Alaska (PCP), Red Rock Lakes NWR (birds of the Tri-State Area flock of the RMP), and Grande Prairie, Alberta (Canada-nesting RMP). All three groups of swans shared a common allele for all loci surveyed, and the mean heterozygosity of the three groups was not different. However, the Alaskan birds possessed alternate alleles at several loci, suggesting that the Alaskan group may differ somewhat from the Grande Prairie and Red Rock Lakes NWR birds. The genetic distance among the three groups was identical, indicating a close genetic relationship among the groups, and led the authors to conclude that the groups sampled were ''virtually identical based on the index of genetic distance.''

Marsolais and White (1997) studied Band-Sharing Coefficients (BSCs) of birds sampled from the PCP, RMP (both Tri-State- and Grande Prairie-nesting birds), and the IP (Ontario flock, comprised of translocated birds from mixed PP/RMP lineages). They found that the IP and RMP birds had much higher BSCs than those of PCP birds, suggesting less genetic diversity in the former two groups. They hypothesized that the low genetic diversity could have been the result of these groups experiencing population ''bottlenecks.'' That is, as the range of the trumpeter swan decreased in the 1800s, the few spatially disjunct groups that remained established at that time were composed of birds with similar genetic traits.

However, as the petitioners (Biodiversity Legal Foundation *et al.* 2000, quoting Marsolais 1994) stipulate, ''the fact that the tristate and interior Canadian populations did not have significantly different mean BSCs, suggests that the tristate population is not less genetically variable than the interior Canadian population.'' Marsolais (1994) goes on to state that genetic differences may exist and could be detected using other techniques. However, subsequent studies to address this latter contention have not been conducted.

Pelizza (unpub. ms.) studied allele frequencies among birds sampled from the PCP, Tri-State-nesting birds, and the High Plains flock of the IP. His results indicated that some differences existed between the PCP birds and those from the latter two groups, but that birds from the Tri-State Area and the High Plains flock were essentially identical. He did not collect samples from the Interior Canada flock.

Thus, although several studies have been conducted, only one has examined directly the genetic relationship between the Canadian- and United States-nesting segments of the RMP. Although that study suggested no differences between the groups, the methods used (starch gel electrophoresis) are dated compared to contemporary techniques using mitochondrial DNA and microsatellites. Thus, Oyler-McCance and Quinn (2001) have initiated a study to better assess potential differences among the two groups of birds. This current study should document the extent of interchange between the Canadian and Tri-State Area flocks of the RMP. The proposed techniques recently have been used to distinguish among sage grouse populations (Oyler-McCance *et al.* 1999).

On the basis of the foregoing discussion of current trumpeter swan genetic information, we conclude that available information does not provide evidence of genetic discontinuity within the meaning of our DPS policy.

(3) *Only surviving natural occurrence*—A population segment may be significant under the DPS policy if it is the only surviving natural occurrence of a taxon that may be more abundant elsewhere as an introduced population outside its historic range. This is not the case with the Tri-State Area trumpeter swan flock.

(4) *Gap in range*—If the Tri-State Area flock were lost, there would not be a significant gap in the range of this species because extant breeding and wintering trumpeter swans are dispersed across North America. The creation of a gap in a species' range can have bearing on gene flow and the demographic stability of a species as a whole. Further, peripheral populations may have genetic characteristics essential to the overall long-term conservation of the species (*i.e.*, they may be genetically different than more central populations) (Lesica and Allendorf 1995). Thus, the consideration of the species' range and the potential for creating a gap in that range can be significant to the conservation of a taxon. However, in this case the potential loss of the Tri-State Area flock is unlikely to have any such effects. Managers have repeatedly established or re-established breeding flocks of trumpeter swans in various areas of the United States and Canada. Restoration flocks derived from exclusively Tri-State Area-nesting swans have been established at several locations, and the loss of a nesting flock in one area would not affect the conservation of the taxon within the meaning of our DPS policy. In addition, several restoration flocks were established with swans from both the Tri-State Area flock and the Pacific Population. Further, RMP swans from Canada winter in the Tri-State Area; thus, trumpeter swans would occur in the area for at least a portion of every year, and may attempt to pioneer vacant areas (note previously mentioned observations of the Interior Canada flock birds in the Tri-State Area during the summer).

Our DPS policy identifies these factors as examples of the types of information that may demonstrate the significance of a population. There may be other considerations we have not explicitly addressed here. However, we do not find another basis to support a conclusion that the Tri-State Area flock is significant to trumpeter swans in North America such that it warrants listing under the Act. In particular, these facts indicate the opposite: (1) The Tri-State Area flock represents only 1 to 3 percent of all trumpeter swans in North America, (2) it has been highly manipulated to the extent that it is probably the least ''natural'' of all trumpeter swan flocks, and (3) a high percentage of restoration flocks outside the Tri-State Area include descendants of Tri-State Area birds that are likely to be genetically similar to those in the Tri-State Area. As previously mentioned, Congressional guidance states that the authority to list DPSs is to be used ''sparingly'' while encouraging the conservation of genetic diversity. We considered the available scientific evidence regarding the Tri-State Area flock's importance to the taxon to which it belongs and conclude that it is not significant.

TABLE 1.—INCIDENCE OF TRUMPETER SWAN HARVEST DURING SWAN SEASON IN THE PACIFIC FLYWAY

Year	Utah		Montana (PF) [1]		Montana (CF) [1]		Nevada	
	Swans examined	Trumpeters detected	Swans examined	Trumpeters detected	Swans examined	Trumpeters detected	Swans examined	Trumpeters detected
1994	474	0	219	1 (juvenile)	31	0	78	0

TABLE 1.—INCIDENCE OF TRUMPETER SWAN HARVEST DURING SWAN SEASON IN THE PACIFIC FLYWAY—Continued

Year	Utah		Montana (PF) [1]		Montana (CF) [1]		Nevada	
	Swans examined	Trumpeters detected	Swans examined	Trumpeters detected	Swans examined	Trumpeters detected	Swans examined	Trumpeters detected
1995	244	3 (1 adult, 2 juveniles)	110	3 (juveniles)	22	0	66	0
1996	701	7 (4 adults, 3 juveniles) [2]	181	3 (adults)	32	0	110	1 (juvenile)
1997	497	3 (2 adults, 1 juvenile)	217	1 (adult)	55	2 (1 adult, 1 juvenile)	116	0
1998	879	1 (juvenile)	168	3 (2 adults, 1 juvenile)	47	2 (adults)	156	0
1999	647	0	153	7 (4 adults, 3 juveniles)	50	2 (adults)	186	0
2000	454	1 (adult)	203	3 (2 adults, 1 juvenile)	57	0	65	0
2001	229	0	244	0	64	2 (1 adult, 1 juvenile)	51	0

[1] Most if not all of these swans likely are from the Interior Canada flock.
[2] In 1996, six of the seven trumpeters detected in Utah's harvest were swans marked and translocated from Idaho and released in Utah as part of a research proposal. The other swan was a marked swan that was translocated from Idaho to Oregon 2 years earlier.

Petition Finding

On the basis of the data in our files, we find that the Tri-State Area flock of trumpeter swans does not constitute a DPS in the meaning of the Act and, therefore, is not a listable entity. The available information does not demonstrate that the flock is discrete, because the proposed DPS is not markedly separated from other segments of trumpeter swans in North America and is not significant under the DPS policy. The petitioners assert that the largely nonmigratory behavior exhibited by this group of birds indicates that the segment is distinct from other flocks because it is physically separated by several hundred miles from other breeding populations. However, current banding and marking information, although limited in extent, indicates that there is some dispersal of swans from the Yellowstone Ecosystem to other parts of the RMP area and vice versa, and that pairings between Tri-State birds and Canadian birds can be expected to occur. All trumpeter swans in the RMP are sympatric during several months (approximate November to March) of the year. Pairing of trumpeter swans generally occurs during the fall and winter months (Johnsgard 1978, Gale *et al.* 1987). Thus, this mixing of birds in winter provides the opportunity for such pairings to occur. One interflock pairing has been documented (Gale *et al.* 1987). Current data do not provide evidence that the Tri-State Area flock is genetically different than other trumpeter swan flocks, and no data suggest physical, physiological, ecological, or significant behavioral differences between the birds in the Yellowstone Ecosystem and the rest of North America.

The petitioners allege that the trumpeter swans in the lower 48 States are managed differently than the Canadian birds, but we find that essentially no differences in management exist, because both countries are party to the Migratory Bird Treaty, coordinate on planning and implementation of swan management goals, conduct similar management activities, and promote population growth of flocks. Both trumpeter and tundra swans are cooperatively managed by Canadian and United States Federal agencies, States, and Provinces through management plans developed specifically for these species.

In North America the species has increased from less than 4,000 birds in 1968 to nearly 24,000 birds in 2000, which represents an average annual population growth of 5.9 percent (Dubovsky and Cornely 2002). The RMP increased from approximately 800 birds in 1968 to more than 3,600 birds in 2000 (Caithamer 2001). This RMP average population growth rate was 4.8 percent per year. Therefore, we conclude that the trumpeter swan is not in need of additional protection beyond the current provisions of the MBTA.

References Cited

A complete list of References Cited is available from the Regional Office or our website (*see* **ADDRESSES**).

Author

The primary author of this document is Chuck Davis, Region 6 Endangered Species Listing Coordinator (*see* **ADDRESSES**).

Authority

The authority for this action is the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*).

Dated: January 15, 2003.

Marshall P. Jones, Jr.,

Acting Director, U.S. Fish and Wildlife Service.

[FR Doc. 03–1804 Filed 1–27–03; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Notice of Availability of a Draft Recovery Plan for the Rough Popcorn Flower (*Plagiobothrys hirtus*) for Review and Comment

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of document availability.

SUMMARY: We, the U.S. Fish and Wildlife Service, announce the availability for public review of a draft

recovery plan for the rough popcorn flower (*Plagiobothrys hirtus*). The draft recovery plan includes specific recovery criteria and measures to be taken in order to delist the rough popcorn flower. We solicit review and comment from local, State, and Federal agencies, and the public on this draft recovery plan.

DATES: Comments on the draft recovery plan must be received on or before March 31, 2003 to receive our consideration.

ADDRESSES: Copies of the draft recovery plan are available for inspection, by appointment, during normal business hours at the following location: Roseburg Field Office, 2900 NW. Stewart Parkway, Roseburg, Oregon 97470 (phone: 541–957–3474). Requests for copies of the draft recovery plan, and written comments and materials regarding this plan should be addressed to Craig Tuss, Field Supervisor, at the above address.

FOR FURTHER INFORMATION CONTACT: Craig Tuss, Field Supervisor, at the above address.

SUPPLEMENTARY INFORMATION:

Background

Recovery of endangered or threatened animals and plants is a primary goal of our endangered species program and the Endangered Species Act (Act) (16 U.S.C. 1531 *et seq.*). A species is considered recovered when the species' ecosystem is restored and/or threats to the species are removed so that self-sustaining and self-regulating populations of the species can be supported as persistent members of native biotic communities. Recovery plans describe actions considered necessary for conservation of the species, establish recovery criteria for downlisting or delisting species, and estimate time and cost for implementing the measures needed for recovery.

The Act, requires the development of recovery plans for listed species unless such a plan would not promote the conservation of a particular species. Section 4(f) of the Act requires that public notice and an opportunity for public review and comment be provided during recovery plan development. We will consider all information presented during a public comment period prior to approval of this recovery plan. Substantive technical comments may result in changes to the plan. Substantive comments regarding recovery plan implementation will be forwarded to appropriate Federal or other entities for consideration during the implementation of recovery actions.

The rough popcorn flower was listed as endangered on January 25, 2000 and is found only in the Umpqua River drainage in Douglas County, Oregon, at sites ranging from 102 to 232 meters (m) (330 to 750 feet) in elevation. Extant, naturally occurring populations of this species occur along the Sutherlin Creek drainage from Sutherlin to Wilbur, adjacent to Calapooya Creek west of Sutherlin, and in roadside ditches near Yoncalla Creek just north of Rice Hill. The northern site is near Yoncalla, and the southern at Wilbur. All known sites were east of Interstate Highway 5 (I–5), until 1998 when a site was discovered at the junction of Stearns Lane and Highway 138, 0.8.kilometers 0.5 miles west of I–5. The eastern site is east of Plat K Road outside of Sutherlin. Historic collections have been made farther east near Nonpareil, but recent surveys (1998 to 1999) did not locate any populations in that area.

The rough popcorn flower is a perennial herbaceous plant, but can be annual depending on environmental conditions. The species occurs in seasonal wetlands. The majority of sites occur on the Conser-type soil series which is characterized as poorly drained flood plain soils. Urban and agriculture development, invasion of non-native species, habitat fragmentation and degradation, and other human-caused disturbances have resulted in substantial losses of seasonal wetland habitat throughout the species' historic range. Conservation measures include establishing a network of protected populations in natural habitat distributed throughout its native range.

The draft recovery plan identifies three recovery zones. The recovery zones are geographically bounded areas containing extant rough popcorn flower populations that are the focus of recovery actions or tasks. The recovery zones include lands both essential and non-essential to the long-term conservation of the rough popcorn flower.

The overall objective of this draft recovery plan is to reduce the threats to the rough popcorn flower to the point it can be reclassified to threatened, with the ultimate goal of being removed from protection entirely. Under the draft recovery plan downlisting of the rough popcorn flower would be contingent upon the following criteria: (1) At least 9 reserves, containing a minimum of 5,000 plants each, are protected and managed to assure their long term survival; (2) a minimum of 1,000 m^2 are occupied by the rough popcorn flower within each reserve, with at least 100 m^2 having a density of 100 plants/m^2 or greater; (3) a minimum of 9 reserves are distributed among the 3 recovery zones (Calapooya Creek, Sutherlin Creek, and Yoncalla Creek), with at least 3 reserves present in each zone; (4) patches within each reserve are within 1 kilometers (2½ miles) of each other to allow pollinator movement and gene flow among them; (5) averages of 5 years of demographic data that indicates populations in at least 7 of the 9 reserves within the 3 recovery zones have average population numbers that are stable or increasing, without decreasing trends lasting more than 2 years; (6) 75 percent or more of the plants are reproductive each year, with evidence of seed maturation and dispersal in all populations; (7) seed germination and seedling recruitment are occurring in all populations; and (8) each existing or reintroduced population is secure from the threats identified in the Reasons for Listing section.

Authority: The authority for this action is section 4(f) of the Endangered Species Act, 16 U.S.C. 1533(f).

Dated: November 5, 2002.

Rowan W. Gould,

Regional Director, Region 1, U.S. Fish and Wildlife Service.

[FR Doc. 03–1826 Filed 1–27–03; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[MT–070–03–1020–PG]

Notice of Public Meeting, Western Montana Resource Advisory Council Meeting

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of public meeting.

SUMMARY: In accordance with the Federal Land Policy and Management Act (FLPMA) and the Federal Advisory Committee Act of 1972 (FACA), the U.S. Department of the Interior, Bureau of Land Management (BLM), Western Montana Resource Advisory Council will meet as indicated below.

DATES: A meeting will be held March 13, 2003, at the BLM Missoula Field Office, 3255 Fort Missoula Road, Missoula, Montana beginning at 9 a.m. The public comment period will begin at 11:30 a.m. and the meeting will adjourn at approximately 3 p.m. A working meeting is planned for April 16 in Dillon, Montana to review the public input gathered during a series of workshops related to the Dillon RMP. The meeting will start at 9 a.m. and will be held at the Dillon Field Office, 1005 Selway Drive.

SUPPLEMENTARY INFORMATION: The 15-member Council advises the Secretary of the Interior, through the Bureau of Land Management, on a variety of planning and management issues associated with public land management in western Montana. At the March 13 meeting, topics we plan to discuss include: Updates on the Dillon and Butte Resource Management Plans, fuels reduction and how it relates to the President's Forest Initiative, the Limestone Hills sub-group, sage grouse planning, and an update on the Dillon standards and guidelines implementation.

All meetings are open to the public. The public may present written comments to the Council. Each formal Council meeting will also have time allocated for hearing public comments. Depending on the number of persons wishing to comment and time available, the time for individual oral comments may be limited. Individuals who plan to attend and need special assistance, such as sign language interpretation, or other reasonable accommodations, should contact the BLM as provided below.

FOR FURTHER INFORMATION CONTACT: Marilyn Krause, Resource Advisory Council Coordinator, at the Butte Field Office, 106 North Parkmont, Butte, Montana 59701, telephone 406–533–7617 or Nancy Anderson, Field Manager, Missoula Field Office, telephone 406–329–3914.

Dated: January 15, 2003.

Nancy Anderson,

Field Manager.

[FR Doc. 03–1807 Filed 1–27–03; 8:45 am]

BILLING CODE 4310–$$–P

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Royalty Policy Committee of the Minerals Management Advisory Board; Notice and Agenda for Meeting

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Notice of meeting.

SUMMARY: The Royalty Policy Committee of the Minerals Management Advisory Board will meet at the New Orleans Hyatt Regency Hotel, New Orleans, Louisiana.

DATES: Wednesday, March 19, 2003, from 1 p.m. to 5 p.m. and Thursday, March 20, 2003, from 8:30 a.m. to 11:30 a.m.

ADDRESSES: The Hyatt Regency New Orleans, 500 Poydras Plaza, New Orleans, Louisiana 70140, telephone (504) 561–1234, fax (504) 523–0488.

FOR FURTHER INFORMATION CONTACT: Mr. Gary Fields, Royalty Policy Committee Coordinator, Minerals Revenue Management, Minerals Management Service, P.O. Box 25165, MS 300B3, Denver, CO 80225–0165, telephone (303) 231–3102, fax (303) 231–3781, e-mail *gary.fields@mms.gov.*

SUPPLEMENTARY INFORMATION: The Secretary of the Interior established a Royalty Policy Committee of the Minerals Management Advisory Board to provide advice on the Department's management of Federal and Indian minerals leases, revenues, and other minerals-related policies. Committee membership includes representatives from States, Indian tribes and allottee organizations, minerals industry associations, the general public, and Federal departments.

At this 16th meeting, the committee will elect a Parliamentarian, receive a subcommittee report on coal and review recommendations from the sodium/potassium subcommittee. The MMS will present reports on financial management, compliance, the Strategic Petroleum Reserve and royalty-in-kind initiatives. The MMS will also discuss the current appeals process, a Federal Energy Regulatory Commission issue and provide a legislative update.

The location and dates of future meetings will be published in the **Federal Register**. The meetings are open to the public without advance registration on a space available basis. The public may make statements during the meetings, to the extent time permits, and file written statements with the committee for its consideration. Written statements should be submitted to Mr. Fields at the mailing address listed in the **FOR FURTHER INFORMATION CONTACT** section. Transcripts of committee meetings will be available 2 weeks after each meeting for public inspection and copying at MMS's Minerals Revenue Management, Building 85, Denver Federal Center, Denver, Colorado.

Authority: Federal Advisory Committee Act, Public Law 92–463, 5 U.S.C. Appendix 1, and Office of Management and Budget Circular No. A–63, revised.

Dated: January 23, 2003.

Lucy Querques Denett,

Associate Director for Minerals Revenue Management.

[FR Doc. 03–1886 Filed 1–27–03; 8:45 am]

BILLING CODE 4310–MR–P

DEPARTMENT OF THE INTERIOR

Bureau of Reclamation

Intent to Solicit Public Comments on the Adoption of an Interim 602(a) Storage Guideline for Management of the Colorado River and to Initiate a National Environmental Policy Act (NEPA) Process

AGENCY: Bureau of Reclamation, Interior.

ACTION: Notice to solicit public comments and initiation of the NEPA process.

SUMMARY: The Secretary of the Department of the Interior (Secretary), acting through the Bureau of Reclamation (Reclamation), is considering the adoption of a specific interim guideline that will assist the Secretary in making a determination of the quantity of water considered necessary as of September 30 of each year, as required by article II (1) of the Criteria for Coordinated Long-Range Operation of Colorado River Reservoirs Pursuant to the Colorado River Basin Project Act of September 30, 1968 (Long-Range Operating Criteria).

DATES: To be most useful, we must receive all comments at the address given below on or before March 14, 2003.

ADDRESSES: You may submit comments to Tom Ryan, Bureau of Reclamation, Upper Colorado Regional Office, 125 South State Street, Salt Lake City, Utah 84138; faxogram (801) 524–5499; e-mail: *tryan@uc.usbr.gov.*

SUPPLEMENTARY INFORMATION: Each year, the Secretary establishes an Annual Operating Plan (AOP) for the Colorado River reservoirs. The AOP describes how Reclamation will manage the reservoirs over a 12-month period, consistent with the Long-Range Operating Criteria. Pursuant to applicable Federal law, Reclamation consults annually with the Colorado River Basin States, Indian tribes, and others interested parties in the development of the AOP. Further, as part of the AOP, the Secretary makes an annual determination under the Long-Range Operating Criteria regarding the quantity of water considered necessary as of September 30 of each year to be in storage as required by section 602(a)(3) of the Colorado River Basin Project Act (602(a) Storage). This determination is important because when projected storage in the Upper Basin reservoirs is greater than 602(a) Storage, releases from Lake Powell are made according to article II (3) of the Long-Range Operating Criteria and section 602(a)(3).

These releases are commonly made to maintain, as nearly as practicable, active storage in Lake Mead equal to the active storage in Lake Powell. These releases are commonly referred to as ''equalization'' releases. When projected storage is less than 602(a) Storage, such equalization releases from Lake Powell are not made.

In July 2000, Reclamation issued a draft environmental impact statement (DEIS) on the proposed adoption of specific criteria under which surplus water conditions may be determined in the Lower Colorado River Basin for 15 years. During the public comment period on the DEIS, the seven Colorado River Basin States submitted information to the Department of the Interior that contained a proposal on interim surplus criteria and a number of other related issues. This information was published in the **Federal Register** on August 8, 2000 (65 FR 48531–38). One component of the Colorado River Basin States' proposal is section V, ''Determination of 602(a) Storage in Lake Powell During the Interim Period,'' and reads as follows:

> During the Interim Period, 602(a) storage requirements determined in accordance with article II (1) of the Criteria [Long-Range Operating Criteria] shall utilize a value of not less than 14.85 maf (elevation 3,630 feet) for Lake Powell (65 FR 48537).

In December 2000, Reclamation issued a final environmental impact statement (FEIS) on the proposed adoption of specific criteria under which surplus water conditions would be determined in the Lower Colorado River Basin through the year 2016. The preferred alternative in the FEIS was based in large part on the Colorado River Basin States' proposal, but as noted in the FEIS, the preferred alternative did not contain all of the specific elements of the Basin States' proposal.

On January 16, 2001, the Secretary signed the record of decision (ROD) for the Colorado River Interim Surplus Guidelines. The FEIS and the ROD did not consider or implement section V of the Colorado River Basin States' proposal (Basin States' proposed 602(a) Storage). Representatives of the Colorado River Basin States have expressed an interest in having the Basin States' proposed 602(a) Storage adopted by the Secretary, through the year 2016, in order to protect Upper Basin storage against the potential drawdown of Lake Mead storage that could occur due to dry hydrology and continued surplus deliveries from Lake Mead to the Lower Division States. The Colorado River Basin is now in its fourth consecutive year of drought.

Under these circumstances, the Secretary believes that it may be prudent to adopt the Basin States' proposed 602(a) Storage, or a reasonable alternative to it, as a guideline for making 602(a) Storage determinations during the period through 2016. As part of the process initiated by this notice, Reclamation will analyze the effects of the Basin States' proposed 602(a) Storage on the Colorado River system.

Reclamation will utilize a public process pursuant to NEPA during the analysis of the Basin States' proposed 602(a) Storage guideline. By this notice, Reclamation invites all interested parties, including the Colorado River Basin States, Indian tribes, water users, members of the general public, organizations, and agencies to present written comments concerning the Basin States' proposed 602(a) Storage and the issues and alternatives that they believe should be analyzed.

Our practice is to make comments, including names and home address of respondents, available for public review. Individual respondents may request that we withhold their home address from public disclosure, which we will honor to the extent allowable by law. If you wish us to withhold your name and/or address, you must state this prominently at the beginning of your comment. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public disclosure in their entirety.

Dated: November 22, 2002.

Rick L. Gold,

Regional Director—Upper Colorado Region.

[FR Doc. 03–1887 Filed 1–27–03; 8:45 am]

BILLING CODE 4310–MN–P

DEPARTMENT OF JUSTICE

Notice of Lodging of Consent Decree Under the Clean Water Act, Clean Air Act, and Resource Conservation and Recovery Act

Notice is hereby given that on January 15, 2003, a proposed Consent Decree in *United States* v. *Koppers Industries, Inc.,* Civil Action No. CV–03–C–0097S, was lodged with the United States District Court for the Northern District of Alabama.

In this action the United States sought civil penalties and injunctive relief for numerous violations of the Clean Water Act at Koppers facilities throughout the United States. The United States also sought civil penalties for violations of the Clean Air Act and the Resource Conservation and Recovery Act occurring at a Koppers' facility in Woodward, Alabama. The alleged violations include Koppers' failure to submit reports and comply with discharge limits required by Clean Water Act permits; Koppers' failure to operate a gas blanketing system at storage tanks in the Woodward facility; and Koppers' use of a crushed tank to store used oil at the Woodward facility. This Woodward facility closed in 1998. In settlement of these allegations, Koppers agrees to pay a $2.9 million civil penalty (plus interest) over three years, and to implement an environmental management system and auditing program at facilities throughout the United States.

The Department of Justice will receive for a period of thirty (30) days from the date of this publication comments relating to the Consent Decree. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611, and should refer to *United States* v. *Koppers Industries, Inc.,* D.J. Ref. 90–5–2–1–06126.

The Consent Decree may be examined at the Office of the United States Attorney, 200 Robert S. Vance Federal Building, 1800 5th Avenue North, Room 200, Birmingham, Alabama, and at U.S. EPA Region 4, Atlanta Federal Center, 61 Forsyth Street, Atlanta, Georgia. A copy of the Consent Decree may also be obtained by mail from the Consent Decree Library, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611. In requesting a copy, please enclose a check in the amount of $29.25 (25 cents per page reproduction cost) payable to the U.S. Treasury.

Ellen Mahan,

Assistant Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. 03–1814 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–15–M

DEPARTMENT OF JUSTICE

Notice of Lodging of the Consent Decree Between the United States of America and Olympic Pipe Line Company Pursuant to the Clean Water Act

Pursuant to 28 CFR 50.7, notice is hereby given that on January 17, 2003, a proposed Consent Decree Between the United States of America and Olympic

Pipe Line Company (Olympic Consent Decree), Civil Action No. CV02–1178R was lodged with the United States District Court for the Western District of Washington.

In this case, the United States sought injunctive relief and civil penalties for the discharge of gasoline into Hanna and Whatcom Creeks in Bellingham, Washington, navigable waters of the United States, and their adjoining shorelines, beginning on June 10, 1999, in violation of sections 301(a) and 311(b)(3) of the Clean Water Act, 33 U.S.C. 1311(a) and 1321(b)(3). The Olympic Consent Decree includes a civil penalty of $2.5 million and comprehensive injunctive relief designed to address all of the known causes of the gasoline spill beginning on June 10, 1999 and covering the entire 400-mile Olympic pipeline system from which the spill occurred. The spill prevention and mitigation program requires Olympic to pay an independent contractor approved by the United States Environmental Protection Agency (EPA) to monitor Olympic's implementation of the program, and to report to EPA. The program, which will last a minimum of five years, includes the following requirements:

- Internal inspections of pipeline using ''Smart PIG'' technology (devices that travel through pipeline to scan for defects);
- Preventive maintenance and repair of pipeline and valve defects;
- Monitoring of construction activities near the pipelines;
- Frequent pipeline surveys;
- Operator training; and
- A Management of Change Program requiring Olympic to analyze changes in its pipeline system for the effect of the changes on the operations and safety of the entire pipeline system.

The Department of Justice will receive for a period of 30 days from the date of this publication comments relating to the Olympic Consent Decree. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611, and should refer to *United States* v. *Shell Pipeline Co.* LP fka Equilon Pipeline Co. LLC and Olympic Pipeline Co., No. CV02–1178R (W.D. Wash.) and D.J. Reference No. 90–5–1–1–06967.

The Olympic Consent Decree may be examined at the Office of the United States Attorney, Western District of Washington, 601 Union Street, 50100 Two Union Square, Seattle, Washington 98101–3903, and at U.S. EPA Region X, 1200 6th Avenue, Seattle, Washington 98101. During the public comment period, the Olympic Consent Decree, may also be examined on the following Department of Justice Web site, *http://www.usdoj.gov/enrd/open.html.* A copy of the Olympic Consent Decree also may be obtained by mail from the Consent Decree Library, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611 or by faxing or e-mailing a request to Tonia Fleetwood *(tonia.fleetwood@usdoj.gov),* fax no. (202) 514–0097, phone confirmation number (202) 514–1547. When requesting a copy from the Consent Decree Library, please enclose a check in the amount of $57.25 (25 cents per page reproduction cost) payable to the U.S. Treasury.

Alternatively, you may request a copy of the Olympic Consent Decree without the attached exhibits by enclosing a check in the amount of $12.75 (25 cents per page reproduction cost) payable to the U.S. Treasury.

Robert E. Maher, Jr.,

Assistant Chief, Environmental Enforcement Service, Environment and Natural Resources Division.

[FR Doc. 03–1812 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–15–M

DEPARTMENT OF JUSTICE

Notice of Lodging of the Consent Decree Between the United States of America and Shell Pipeline Company LP fka Equilon Pipeline Company LLC Pursuant to the Clean Water Act

Pursuant to 28 CFR 50.7, notice is hereby given that on January 17, 2003, a proposed Consent Decree Between the United States of America and Shell Pipeline Company LP (Shell) fka Equilon Pipeline Company LLC (Shell Consent Decree), Civil Action No. CV02–1178R was lodged with the United States District Court for the Western District of Washington.

In this case, the United States sought civil penalties for the discharge of gasoline into Hanna and Whatcom Creeks in Bellingham, Washington, navigable waters of the United States, and their adjoining shorelines, beginning on June 10, 1999, in violation of sections 301(a) and 311(b)(3) of the Clean Water Act, 33 U.S.C. 1311(a) and 1321(b)(3). The Shell Consent Decree includes a civil penalty of $5 million and other relief consisting of a comprehensive pipeline spill prevention program covering 2139 miles of pipeline in seven states. The pipeline systems covered by the spill prevention program are Shell's East, North, Chase, and Orion Systems in the states of Colorado, Kansas, Illinois, Indiana, Ohio, Oklahoma, and Texas. The spill prevention program requires Shell to pay an independent contractor approved by the United States Environmental Protection Agency (EPA) to monitor Shell's implementation of the spill prevention program, and to report to EPA. The spill prevention program, which will last a minimum of five years, includes the following requirements:

- Internal inspections of pipeline using ''Smart PIG'' technology (devices that travel through pipeline to scan for defects);
- Installation, maintenance, and testing of corrosion control equipment;
- Testing and repair of leak detection systems;
- Installation of block valves and check valves to divert the flow of gasoline in an emergency;
- Protective measures for exposed pipe;
- Protective measures for insufficiently buried pipe near commercially navigable waterways;
- Monitoring of construction activities near the pipelines;
- Frequent pipeline surveys;
- Operator training; and
- A Management of Change Program requiring Shell to analyze changes in its pipeline systems for the effect of the changes on the operations and safety of the affected pipeline system.

The Department of Justice will receive for a period of 30 days from the date of this publication comments relating to the Shell Consent Decree. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611, and should refer to *United States* v. *Shell Pipeline Co. LP fka Equilon Pipeline Co. LLC and Olympic Pipeline Co.*, No. CV02–1178R (W.D. Wash.) and D.J. Reference No. 90–5–1–1–06967.

The Shell Consent Decree may be examined at the Office of the United States Attorney, Western District of Washington, 601 Union Street, 50100 Two Union Square, Seattle, Washington 98101–3903, and at U.S. EPA Region X, 1200 6th Avenue, Seattle, Washington 98101. During the public comment period, the Shell Consent Decree, may also be examined on the following Department of Justice Web site, *http://www.usdoj.gov/enrd/open.html.* A copy of the Shell Consent Decree also may be obtained by mail from the Consent Decree Library, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611 or by faxing or e-mailing a request to Tonia Fleetwood *(tonia.fleetwood@usdoj.gov)*, fax no.

(202) 514–0097, phone confirmation number (202) 514–1547. When requesting a copy from the Consent Decree Library, please enclose a check in the amount of $100 (25 cents per page reproduction cost) payable to the U.S. Treasury.

Alternatively, you may request a copy of the Shell Consent Decree without the attached exhibits by enclosing a check in the amount of $18.50 (25 cents per page reproduction cost) payable to the U.S. Treasury.

Robert E. Maher, Jr.,

Assistant Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. 03–1813 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–15–M

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

Manufacturer of Controlled Substances Notice of Application

Pursuant to § 1301.33(a) of Title 21 of the Code of Federal Regulations (CFR), this is notice that on June 21, 2002, Bristol-Myers Squibb Pharma Company, 1000 Stewart Avenue, Garden City, New York 11530, made application by renewal to the Drug Enforcement Administration (DEA) for registration as a bulk manufacturer of the basic classes of controlled substances listed below:

Drug	Schedule
Oxycodone (9143)	II
Hydrocodone (9193)	II
Oxymorphone (9652)	II

The firm plans to manufacture the listed controlled substances to make finished products.

Any other such applicant and any person who is presently registered with DEA to manufacture such substances may file comments or objections to the issuance of the proposed registration.

Any such comments or objections may be addressed, in quintuplicate, to the Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration, United States Department of Justice, Washington, DC 20537, Attention: DEA Federal Register Representatives (CCR), and must be filed no later than (60 days from publication).

Dated: January 6, 2003.

Laura M. Nagel,

Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration.

[FR Doc. 03–1914 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–09–M

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

Manufacturer of Controlled Substances; Notice of Registration

By Notice dated June 24, 2002, and published in the **Federal Register** on July 10, 2002, (67 FR 45764), Cayman Chemical Company, 1180 East Ellsworth Road, Ann Arbor, Michigan 48108, made application to the Drug Enforcement Administration (DEA) to be registered as a bulk manufacturer of tetrahydrocannabinols (7370), a basic class of controlled substance listed in Schedule I.

The firm plans to manufacture tetrahydrocannabinols for sale to their customers.

No comments or objections have been received. DEA has considered the factors in Title 21, U.S.C. 823(a) and determined that the registration of Cayman Chemical Company to manufacture the listed controlled substance is consistent with the public interest at this time. DEA has investigated Cayman Chemical Company on a regular basis to ensure that the company's continued registration is consistent with the public interest. These investigations have included inspection and testing of the company's physical security system, audits of the company's records, verification of the company's compliance with state and local laws, and a review of the company's background and history. 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: January 6, 2003.

Laura M. Nagel,

Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration.

[FR Doc. 03–1916 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–09–M

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

MDI Pharmaceuticals Revocation of Registration

On September 24, 2001, the Administrator of the Drug Enforcement Administration (DEA), issued an Order to Show Cause and Immediate Suspension of Registration to MDI Pharmaceuticals (MDI) located in Dillon, Montana. MDI was notified of a preliminary finding that pursuant to evidence set forth therein, it was responsible for, inter alia, the diversion of large quantities of list I chemicals into other than legitimate channels. Based on his preliminary findings, and pursuant to 21 U.S.C. 824(d) and 21 CFR 1309.44(a), as well as the authority granted under 21 CFR 0.100, the Administrator ordered the immediate suspension of MDI's DEA Certificate of Registration, 004629IEY, as a distributor of list I chemicals, effective immediately. The suspension was to remain in effect until a final determination was reached in these proceedings.

The Order to Show Cause and Immediate Suspension further informed MDI of an opportunity to request a hearing to show cause as to why DEA should not revoke its DEA Certificate of Registration, and deny any pending applications for renewal or modification of that registration for reason that such registration is inconsistent with the public interest, as determined by 21 U.S.C. 823(h). MDI was also notified that should no request for hearing be filed within 30 days, its right to a hearing would be deemed waived.

On September 26, 2001, a copy of the Order to Show Cause and Immediate Suspension was served upon MDI's owners by DEA Diversion Investigators. DEA has not received a request for hearing or any other reply from MDI or anyone purporting to represent the firm in this matter. Therefore, the Deputy Administrator, finding that (1) 30 days have passed since the receipt of the Order to Show Cause, and (2) no request for a hearing having been received, concludes that MDI is deemed to have waived its hearing right. After considering material from the investigative file in this matter, the Deputy Administrator now enters his final order without a hearing pursuant to 21 CFR 1301.43(d) and (e) and 1301.46.

The Deputy Administrator finds as follows: list I chemicals are those that may be used in the manufacture of a controlled substance in violation of the

Controlled Substances Act. 21 U.S.C. 801(34); 21 CFR 1310.02(a). Pseudoephedrine and ephedrine are list I chemicals that are commonly used to illegally manufacture methamphetamine, a Schedule II controlled substance. Methamphetamine is an extremely potent central nervous system stimulant, and its abuse is a growing problem in the United States.

A ''regulated person'' is one who manufactures, distributes, imports, or exports inter alia a listed chemical. 21 U.S.C. 802(38). A ''regulated transaction'' is inter alia, a distribution, receipt, sale, importation, or exportation of a threshold amount of a listed chemical. 21 U.S.C. 802(39). The Deputy Administrator finds all parties mentioned herein to be regulated persons, and all transactions mentioned herein to regulated transactions, unless otherwise noted.

The Deputy Administrator finds that on June 23, 1999, Isabelle DeLuce (Ms. DeLuce) submitted an application on behalf of MDI for registration with DEA as a distributor of list I chemicals. At the time of the submission of its application, MDI was a distributor of various non-chemical products such as vitamins, herbal products and novelty items. MDI was and is operated by Ms. DeLuce and her husband Michael Uzan (Mr. Uzan).

On October 27, 1999, DEA Diversion Investigators conducted an on-site pre-registration interview of Ms. DeLuce and Mr. Uzan at MDI's proposed registered location. During the interview, investigators warned MDI's owners about the diversion of ephedrine and pseudoephedrine to the illicit production of methamphetamine. The investigators also discussed DEA regulations pertaining to list I chemicals. Ms. DeLuce and Mr. Uzan informed the investigators that they understood the regulations and would comply with all laws pertaining to listed chemicals. Ms. DeLuce also informed investigators that she anticipated that listed chemicals would comprise only 20% of MDI's sales and that these products would be sold to convenience stores and gas stations located only in the State of Montana. Shortly thereafter, MDI was issued a DEA registration as a list I chemical distributor for ephedrine, phenylpropanolamine and pseudoephedrine.

The Deputy Administrator finds that MDI has purchased listed chemicals from a DEA registrant that was the subject of a criminal investigation involving the mishandling of these products. A review of the investigative file reveals that on August 3, 2000, a Federal search warrant was executed at Wholesale Outlet at its location in Beaumont, Texas. At the time the warrant was executed, Wholesale Outlet was a DEA-registered distributor of list I chemicals. The issuance of the search warrant arose from an ongoing DEA investigation into Wholesale Outlet's listed chemical handling practices. Mediplas Innovations; Suspension of Shipments, 67 FR 41256, 41259 (2002). During the execution of the search warrant, law enforcement officers recovered, among other things, numerous invoices reflecting MDI's purchases of various products from Wholesale Outlet. Of note was MDI's purchase of $15,840 worth of single entity ''Twin Pseudo'' brand pseudoephedrine, 60 mg. in 120-count bottles.

Effective May 30, 2002, the Deputy Administrator sustained DEA's suspension of listed chemical shipments imported by a DEA registered importer and destined for sale to Wholesale Outlet. Mediplas at 41256, 41264. Among the reasons cited for sustaining the suspensions was the pending criminal investigation involving Wholesale Outlet, including allegations of is suspected misconduct in the handling of list I chemicals, as well as a DEA audit which revealed Wholesale Outlet's failure to account for listed chemicals that it purchased, in violation of 21 U.S.C. 830(a) and 842(a)(10) and 21 CFR 1310.03 and 1310.06. Mediplas at 41263–64. Moreover, the Deputy Administrator found in sustaining the suspensions that pseduoephedrine products distributed by Wholesale Outlet (the same products purchased by MDI from the firm) were found at various clandestine locations throughout the United States and used in the illicit manufacture of methamphetamine.

On August 17, 2000, a DEA Diversion Investigator requested that Ms. DeLuce provide a current customer/supplier list for listed chemicals. Ms. DeLuce informed the investigator that all but two of MDI's 72 customers were located in Nevada, with the majority conducting business in the greater Las Vegas. After providing the requested list of suppliers, Ms. DeLuce stated that MDI purchased 50 to 70 cases of pseudoephedrine, 60 mg., in 120-count bottles, and twenty-two cases of pseudoephedrine, 60 mg. in 60-count bottles on a monthly basis.

The Deputy Administrator's review of the investigative file further reveals that on or about November 30, 2000, Ms. DeLuce and Mr. Uzan were stopped in their automobile by the Las Vegas Police Department and issued a traffic citation. At the time of the traffic stop, the police officer noticed several cases of pseudoephedrine in the back seat of the vehicle. Ms. DeLuce and Mr. Uzan volunteered that they were distributing or selling pseudoephedrine to local businesses. On a subsequent occasion, Ms. DeLuce was again stopped in her vehicle by law enforcement officers while transporting quantities of pseudoephedrine. During this traffic stop, Ms. DeLuce provided a copy of her DEA registration and informed law enforcement officers that she was aware that pseudoephedrine could be diverted to the illicit manufacture of methamphetamine. During this traffic stop, Ms. DeLuce told the officers that she limited her sales to just one case per customer and that she sold pseudoephedrine to 50 clients about once a month in the greater Las Vegas area because she could not find enough customers in Montana.

Pursuant to 21 CFR 1310.05(a)(1) DEA registrants are required to notify DEA in the event of any regulated transactions involving an extraordinary quantity, an uncommon method of payment or delivery, or any other circumstance that indicates that the listed chemical may be used unlawfully. The Deputy Administrator finds that the manner in which Ms. DeLuce and Mr. Uzan transported listed chemicals products in their automobile created a climate for diversion. Therefore, its failure to notify DEA of the uncommon means of transporting a listed chemical results in a finding that MDI, through the actions of its owners, was in violation of section 1310.05.

On April 15, 2001, pursuant to an administrative subpoena, MDI produced its records for the purchase of pseudoephedrine between March 2000 and October 2000. These records revealed that MDI purchased 106,563 bottles of pseudoephedrine valued at $342,758.00 from four (4) different suppliers over that time period.

MDI also produced its customer list for DEA inspection. A majority of the customers were located in Las Vegas, Nevada, and consisted primarily of gas stations, smoke shops, mini marts and other types of convenience stores. Included among MDI's list of customers was Mike's Smoke Shop, located at 2923 North Avenue in Grand Junction, Colorado. This establishment was owned by Mike Yako (Mr. Yako). During a follow-up investigation on February 13, 2001, DEA special agents discovered that Mike's Smoke Shop had moved to its business location around July 2000 but was evicted from that location in either August or September 2000 for non-payment of rent. Further investigation revealed that during the

time this establishment conducted business, it maintained very little inventory.

A subsequent review of MDI's sales records revealed that from July 31 to November 16, 2000, the firm sold to Mike's Smoke Shop (2923 North Avenue location) approximately 65,650 tablets of pseudoephedrine. During a period of just under three months, MDI distributed an average of over 21,800 tablets per month to this small retailer of tobacco products. Many of the customer receipt documents for these transactions were signed by ''M. Yako'' or ''S. Issa.'' MDI continued its sale of pseudoephedrine products to Mike's Smoke Shop even after that establishment had closed. Many of these transactions took place within a week of one another. Given the nature of this purported business, the distribution of pseudoephedrine to this establishment was apparently in excess of legitimate demand. The Deputy Administrator finds that MDI failed to report to DEA the sale of an extraordinary quantity of listed chemicals and to verify the existence and validity of a business entity ordering listed chemicals, as required by 21 CFR 1310.05(a) and 1310.07. Furthermore, MDI distributed a listed chemical to this establishment knowing or having reasonable cause to believe that the listed chemical would be used to manufacture illicit methamphetamine in violation of 21 U.S.C. 841(c)(2) (2001).

On February 13, 2001, DEA special agents went to a second establishment under the name of Mike's Smoke Shop, located at 1010 ½ N. 5th St., Grand Junction, Colorado, also owned by Mr. Yako. While signs posted outside the establishment listed hours of operation, it appeared that the business had not been open for some time, DEA agents observed mail lying on the floor inside the door covered by dirt.

Nevertheless, a subsequent review of sales records revealed that between August 9, 2000, and April 18, 2001, MDI sold 3312 bottles of 120-count 60 mg. (397,400 tablets) pseudoephedrine to Mike's Smoke Shop at its 1010 ½ North 5th Street location. During this eight-month period, MDI sold an average of 414 bottles or 49,680 tablets per month this small, retail smoke shop. As with the previous Mike's Smoke Shop location, many of the customer receipt documents for these transactions were signed by ''M. Yako'' or ''S. Issa.'' Given the nature of this purported business, the distribution of pseudoephedrine to this establishment was apparently in excess of legitimate demand. MDI again failed to report to DEA the sale of an extraordinary quantity of listed chemicals and to verify the existence and validity of a business entity ordering listed chemicals, as required by 21 CFR 1310.05(a) and 1310.07. MDI also distributed a listed chemical to this establishment knowing or having reasonable cause to believe that the listed chemical would be used to manufacture illicit methamphetamine in violation of 21 U.S.C. 841(c)(2) (2001).

MDI also listed as a customer Paradise Smoker, also located in Grand Junction Colorado, and purportedly owned by an individual by the name of Samer Issa. When DEA special agents sought to verify the existence of the business, they were unable to locate it. Nevertheless, a review of MDI's shipment records revealed that between August 10, 2000 and November 16, 2001, the firm sold approximately 190,080 pseudoephedrine tablets to this small retailer of tobacco products. As with the Mike's Smoke Shop locations, many of the customer receipts were signed on behalf of Paradise Smoker by ''M. Yako'' or ''S. Issa.'' Given the nature of this purported business, the distribution of pseudoephedrine to this establishment was far in excess of legitimate demand. Therefore, with respect to regulated transactions involving Paradise Smoker, the Deputy Administrator finds that MDI failed to report to DEA the sale of an extraordinary quantity of listed chemicals and to verify the existence and validity of a business entity ordering listed chemicals, as required by 21 CFR 1310.05(a) and 1310.07. MDI also distributed a listed chemical knowing or having reasonable cause to believe that the listed chemical would be used to manufacture illicit methamphetamine in violation of 21 U.S.C. 841(c)(2) (2001).

On February 13, 2001, DEA Special Agents interviewed an employee of one of MDI's retail customers, Special Smoke Shop of Delta, Colorado. This small retailer of tobacco products was purportedly owned by Suhail Issa. The employee informed investigators that tobacco products were the only products sold in the store that its owner ordered boxes of goods, which were paid for by money orders. The employee also revealed that the inventory of these boxes was never sold from the store; rather, the owner removed these boxes as soon as they were delivered to the store.

DEA's review of sales records revealed that MDI sold approximately 3,600 bottles of 120-count 60 mg. (432,000 tablets) pseudoephedrine to Special Smoke Shop between August 10, 2000 and April 18, 2001. During this eight-month period, MDI sold an average of 450 bottles (or 54,000 tablets) per month to this establishment. Again, several of the customer receipt documents showed that they were signed on behalf of this customer by ''M. Yako'' and ''S. Issa.'' Given the nature of this purported business, MDI's distribution of pseudoephedrine to this establishment was far in excess of legitimate demand. Therefore, with respect to regulated transactions involving Special Smoke Shop, the Deputy Administrator finds that MDI failed to report to DEA the sale of an extraordinary quantity of listed chemicals and to verify the existence and validity of a business entity ordering listed chemicals, as required by 21 CFR 1310.05(a) and 1310.07. MDI also distributed a listed chemical to this establishment knowing or having reasonable cause to believe that the listed chemical would be used to manufacture illicit methamphetamine in violation of 21 U.S.C. 841(c)(2)(2001).

Shortly thereafter, a DEA Special Agent visited another MDI retail customer, Special Smoke (an apparent name variation of ''Special Smoke Shop''), located in Fruita, Colorado. Special Smoke was also a retailer of tobacco products and purportedly owned by Suhail Issa. The Special Agent, posing as a customer, noticed that two bottles of pseudoephedrine were displayed in the store along with a sign that read, ''Limit three (3) per purchase.'' A subsequent review of MDI sales records revealed that between January 4, 2000 and April 13, 2001, the company sold 3312 bottles of 120-count 60 mg. (397,440 tablets) pseudoephedrine to Special Smoke. Some of these transactions took place within two to five days of one another.

In addition, several of the customer receipt documents showed that they were signed by ''M. Yako'' and ''S. Issa'' as well as by other persons associated with the Mike's Smoke Shop locations, Paradise Smoke and Special Smoke Shop. Given the nature of this purported business, the distribution of pseudoephedrine to this establishment was far in excess of legitimate demand. Therefore, with respect to regulated transactions involving Special Smoke Shop, the Deputy Administrator finds that MDI failed to report to DEA the sale of an extraordinary quantity of listed chemicals and to verify the existence and validity of a business entity ordering listed chemicals, as required by 21 CFR 1310.05(a) and 1310.07. MDI also distributed a sited chemical knowing or having reasonable cause to believe that the listed chemical would be used to manufacture illicit methamphetamine in violation of 21 U.S.C. 841(c)(2) (2001).

The Deputy Administrator's review of the investigative file reveals that pseudoephedrine products distributed by MDI have been uncovered at numerous clandestine methamphetamine settings throughout the United States and/or discovered in the possession of individuals apparently involved in the illicit manufacture of methamphetamine. On February 20, 2001, the Las Vegas Metropolitan Police Department (LVMPD) arrested three individuals in an apartment complex in response to a small fire in their unit. At the time of the arrest, LVMPD officers discovered a methamphetamine laboratory inside the apartment. Numerous items associated with the illicit manufacture of methamphetamine were also recovered from the apartment, including three empty 120-count bottles of MDI brand 60mg. pseudoephedrine tablets.

On April 4, 2001, two individuals were arrested by the LVMPD when a search of a residence revealed items associated with the illicit manufacture of methamphetamine, including twenty 120-count bottles of MDI brand 60mg. pseudoephedrine tablets. The investigative file further reveals that from April 16 to August 8, 2001, there were approximately thirteen additional seizures of MDI brand pseudoephedrine products at various clandestine laboratory settings. These seizures occurred primarily in the Las Vegas area, as well as at locations in Colorado and California.

The Deputy Administrator finds that on February 22, 2001, the Federal Express office in St. George, Utah received six cases of pseudoepedrine which were shipped by MDI purportedly to six different business locations; however, all six cases were picked up by one person in a vehicle registered to Samar Issa. Business records for the city of St. George had no current information for three of the business entities. Business licenses for the other three businesses were issued to Marogy Marogy (later determined to be Samer Issa's brother-in-law), Mike Yako and a ''Suhel Aesa.''

On March 14, 2001, a DEA Task Force Officer (TFO) acting in an undercover capacity met with Mike Yako at a location in Las Vegas, Nevada to arrange the purchase of a half case of pseudoephedrine. After agreeing to a price for half a case of pseudoephedrine, Mr. Yako was observed by law enforcement officers going into a storage unit, where he later emerged carrying a brown box which he placed in the trunk of his car. Mr. Yako then removed from the car trunk a bottle of MDI brand pseudoephedrine, which he handed to the TFO. Yako then stated to the TFO that MDI brand ''is doing so well'' his store put their own labels on the bottles. Mr. Yako then accepted from the undercover TFO $2,000 cash for 72 bottles of MDI pseudoephedrine tablets. During an April 3, 2001 undercover operation, the TFO stated his intentions to purchase five cases of pseudoephedrine from Mr. Yako in the near future, to which Mr. Yako replied, ''no problem.''

On March 18, 2001, a Colorado State Trooper made a traffic stop of a vehicle driven by Suhail Issa, who was accompanied by Mike Yako. Mr. Yako informed the trooper that he was visiting Colorado to oversee ''smoke shop'' stores that he owned in the state. He further stated that the two were on their way to Las Vegas, and had planned a temporary stop in Fruita, Colorado, to purchase gasoline for the vehicle they were driving. After obtaining permission to search the vehicle, the trooper found three boxes of pseudoephedrine. Contained within the three boxes were Federal Express shipping labels dated April 16, 2001, and invoices from MDI to Special Smoke locations in Fruita, Grand Junction, and Delta, Colorado. Mike Yako explained that the three boxes were ''stuff for my business.'' The trooper seized the three boxes, but did not arrest the two passengers.

On May 24, 2001, Diversion Investigators visited Ms. DeLuce and Mr. Uzan at their residence in Dillon, Montana. DEA personnel discussed with Ms. DeLuce and Mr. Uzan information regarding MDI pseudoephedrine products that were found at various clandestine methamphetamine settings. In response, Ms. DeLuce explained that she limits her customers to only two cases per month and that she sells pseudoephedrine in bottles rather than in blister packs because her customers prefer bottles. She also stated that she had 137 customers, most of who were located in Las Vegas.

DEA also discussed with Ms. DeLuce the above referenced traffic stop of Suhail Issa and Mile Yako by the Colorado State Police. Ms. DeLuce acknowledged that these individuals were customers of MDI, and that she had been informed of the traffic stop. Ms. DeLuce also stated that she thought the two customers fabricated the story about the seizure in order to obtain more pseudoephedrine from MDI. Ms. DeLuce further added that despite her suspicions regarding the circumstances of traffic stop and the fact that the two customers were transporting pseudoephedrine products in the trunk of an automobile, she failed to report these matters to DEA as a suspicious transactions. Ms. DeLuce explained that she did not report the incident because she believed DEA was already aware of the seizure.

Despite her representations to DEA personnel, the Deputy Administrator finds that information previously communicated to Ms. DeLuce regarding the traffic stop of her customers, and their being found in possession of caseload quantities of pseudoephedrine which were later seized, should have raised red flags that these products were being diverted to illicit uses. Ms. DeLuce admitted that the circumstances surrounding the traffic stop were suspicious. As a registrant entrusted with securing a product that is frequently diverted to illicit uses, MDI was required to notify DEA of the suspicious circumstances surrounding the traffic stop of its customers pursuant to 21 CFR 1310.05(a).

The investigative file further reveals that Ms. DeLuce and Mr. Uzan informed DEA personnel that because of the traffic stop involving Mister Issa and Yako, MDI suspended all sales of its products to any establishment in which these customers were affiliated. They further indicated that the ''smoke shop'' stores operated by Issa and Yako in Colorado had closed. However, DEA subsequently obtained Federal Express records which showed that on at least thirty-nine separate occasions following the traffic stop by the Colorado State Police, MDI continued its shipment of caseload quantities of pseudoephedrine to business establishments operate by Suhail Issa and/or Mike Yako. Included among these transactions were numerous shipments of listed chemicals to ''smoke shops'' in Colorado. At least three of the transactions occurred after Ms. DeLuce assured DEA personnel that MDI no longer sold listed chemicals to these customers.

A further review of the investigative file reveals that MDI shipped pseudoephedrine products to a customer in St. George, Utah. Ms. DeLuce informed DEA personnel that MDI later determined that the customer was operating from a fictitious address. However, Ms. DeLuce admitted that MDI failed to report this suspicious transaction, as required by 21 CFR 1310.05(a)(1)

The Administrator of DEA made a preliminary finding that MDI has been responsible for the diversion of large quantities of pseudoephedrine into other than legitimate channels, in violation of 21 U.S.C. 830(b)(3) and 841(c0(2). The Administrator also found that despite MDI's awareness of

problems associated with pseudoepherdrine diversion, and laws pertaining to listed chemicals, the firm had continually and consistently violated DEA laws pertaining listed chemicals, thus resulting in large quantities of pseudoepherdrine being diverted to the illicit production of methamphetamine. Therefore, pursuant to 21 U.S.C. 824(d), the Administrator of DEA issued an immediate suspension of MDI's DEA Certificate of Registration.

As noted above, on September 26, 2001, DEA Diversion Investigators served the Order to Show Cause and Immediate Suspension on Ms. DeLuce at her residence in Dillon, Montana. On that same date, Ms. DeLuce and Mr. Uzan were arrested by DEA Special Agents and charged with offenses related to the unlawful distribution and possession of listed chemicals. At the time of her arrest, Ms. DeLuce agreed to answer questions regarding her sale of listed chemicals and customers who purchased these products from MDI.

Ms. DeLuce informed DEA agents that she knew her products were being sold ''on the street.'' She further admitted that she knew Samer and Suhail Issa, as well as Fehmi Awad (Mr. Awad) were probably abusing pseudoephedrine (*i.e.,* ''selling too much''). Ms. DeLuce further stated that she knew Mr. Awad was picking up pseudoephedrine products at four different stores, and Samer Issa was selling the products to illicit methamphetamine manufacturers for about a year. She further admitted knowing that certain customer accounts in Utah and Colorado where MDI shipped pseudoephedrine products were fronts for Samer Issa. Samer Issa reportedly set these stores up in the name of his brother as well as in the names of others.

Ms. DeLuce further informed to DEA agents that she knew pseudoephedrine was a ''hot item'' in Las Vegas because of the methamphetamine problem, and that 97% of MDI's customers were in that area. She estimated that her company made a profit from the sale of pseudoephedrine of between $700,000 to $800,000 a year at approximately $1,000 per case. Ms. DeLuce also disclosed that Samer Issa informed her that a case of pseudoephedrine sold for approximately $4000.00 on the street. Despite suspicions that her customers were selling MDI pseudoephedrine products to illicit methamphetamine cooks, Ms. DeLuce said that she essentially closed her eyes and ignored the actions of her customers. She further admitted that it was hard to stop selling a product that sold for $1,000 a case.

The Deputy Administrator's review of the investigative file reveals that on October 10, 2001, a Federal Grand Jury in the District of Nevada issued a twenty-nine count indictment against Ms. DeLuce, Mr. Uzan, as well as Samer and Suhail Issa, Fehmi Awad, Mike Yako, and two additional individuals. Among the charged offenses were conspiracy to distribute a listed chemical with knowledge or reasonable cause to believe it would be used to manufacture a controlled substance in violation of 21 U.S.C. 846 and 841(c)(2); possession of a listed chemical in violation of 21 U.S.C. 841(c)(2) and 18 U.S.C. 2; and unlawful use of a communication facility, namely telephones and telephone wires, in causing and facilitating the commission of a conspiracy, in violation of 21 U.S.C. 843(b). These matters are currently pending resolution.

The Deputy Administrator finds that the above-cited evidence provides ample grounds for an immediate suspension pursuant to 21 U.S.C. 824(d). These grounds also provide the basis for the revocation of MDI's DEA Certificate of Registration.

Pursuant to 21 U.S.C. 824(a), the Deputy Administrator may revoke a registration to distribute list I chemicals upon a finding that the registrant has committed such acts as would render his registration under section 823 inconsistent with the public interest as determined under that section. Pursuant to 21 U.S.C. 823(h), the following factors are considered in determining the public interest:

(1) Maintenance of effective controls against diversion of listed chemicals into other than legitimate channels;

(2) Compliance with applicable Federal, State, and local law;

(3) Any prior conviction record under Federal or State laws relating to controlled substances or to chemicals controlled under Federal or State law;

(4) Any past experience in the manufacture and distribution of chemicals; and

(5) Such other factors as are relevant to and consistent with the public health and safety.

As with the public interest analysis for practitioners and pharmacies pursuant to subsection (f) of section 823, these factors are to be considered in the disjunctive; the Deputy Administrator may rely on any one or combination of factors of factors, and may give each factor the weight he deems appropriate in determining whether a registration should be revoked or an application for registration denied. *See, e.g.* Energy Outlet, 64 FR 14269 (1999). *See* also Henry J. Schwartz, Jr., M.D. 54 FR 16422 (1989).

With respect to factor one, maintenance of effective controls against diversion, the Deputy Administrator finds substantial evidence in the investigative file that MDI, through its owners Isabelle DeLuce and Michael Uzan, participated in the unlawful diversion of pseudoephedrine having reasonable cause to believe that it would be used to manufacture illicit methamphetamien. Ms. DeLuce and Mr. Uzan transported bottles of pseudoephedrine in the trunk of their automobile and distributed these products to gas stations, smoke shops, mini marts and other convenience stores in the vicinity of Las Vegas, Nevada, an area known for large numbers of seizures involving clandestine methamphetamine laboratories. DEA previously denied the application of a retail establishment that sought registration as a distributor of list I chemicals when it was found through ''past DEA investigations and experience'' that the primary source for diversion of listed chemicals in areas where the applicant sought to distribute, specifically in Las Vegas, Nevada, were mini marts and other types of convenience stores. Sinbad Distributing, 67 FR 10232, 10233 (2002). *See e.g.* K.V.M. Enterprises, 67 FR 70968 (2002) (denial of application based in part upon information developed by DEA that the applicant proposed to sell listed chemicals to gas stations, and the fact that these establishments in turn have sold listed chemical products to individuals engaged in the illicit manufacture of methamphetamine).

Factor one is also relevant to MDI's distribution of large quantities of pseudoephedrine products to numerous establishments associated with Mike Yako and Saher Issa, despite knowledge on the part of Ms. DeLuce and Mr. Uzan that these establishments were fronts for obtaining listed chemicals for use in the illicit manufacture of methamphetamine. On numerous occasions, MDI failed to report to DEA the sale of an extraordinary quantity of listed chemicals or verify the existence and validity of a business entity ordering listed chemicals, as required by 21 CFR 1310.05(a) and 1310.07. MDI failed to notify DEA that its customer was stopped by law enforcement authorities, and had cases of pseudoephedrine taken from the trunk of an automobile which was seized. In addition, MDI failed to notify DEA that it had shipped pseudoephedrine products to a customer with a fictitious address.

Regarding factor two, the investigative file reveals that MDI failed to comply with applicable Federal laws by not

reporting the sale of extraordinary quantities of listed chemicals or uncommon method of delviery; verify the existence and validity of business entities; and distributed listed chemicals with knowledge that they were being diverted, as set forth in factor one above. MDI also failed to make required reports of suspicious listed chemical transactions pursuant to 21 U.S.C. 830(b)(1)(A), in that the firm distributed large quantities of pseudoephedrine tablets to smoke shops and other convenience stores in quantities that apparently exceeded legitimate demand for these products.

In addition, MDI's owners were notified by DEA Diversion Investigators of dangers surrounding the diversion of list I chemicals. Ms. DeLuce demonstrated her knowledge of this fact on several occasions, as evidenced by her statement to a law enforcement officer during a traffic stop that she was aware of the illicit uses of pseudoephedrine. Therefore, MDI's distribution of large quantities of pseudoephedrine to smoke shops and convenience stores were in violation of 21 U.S.C. 841(d)(2) (2001), since its owners, by their own admission, knew that these products were being diverted to the illicit manufacture of methamphetamine. *See, e.g.* Ace Wholesale & Trading Co., 67 FR 12574, 12576 (2002).

The Deputy Administrator also finds factor two applicable to MDI's failure to notify DEA of the circumstances surrounding the traffic stop of its customers in the State of Colorado, and the seizure of MDI pseudoephedrine products that were being transported in the customer's automobile. Factor two is also applicable to the criminal indictment by a Federal Grand Jury of Ms. DeLuce, Mr. Uzan, as well as several individuals who purchased pseudoephedrine products from MDI. These charges stem from allegations regarding the unlawful distribution and possession of listed chemicals, and are pending resolution.

Notwithstanding the pending criminal charges facing its owners, with respect to factor three, there is no evidence in the investigative file that MDI, Ms. DeLuce or Mr. Uzan have any prior conviction record under Federal or State laws relating to controlled substances or chemicals.

With respect to factor four, past experience in the manufacture and distribution of chemicals, the Deputy Administrator finds substantial evidence in the investigative file that Ms. DeLuce and Mr. Uzan failed to maintain adequate controls in distributing pseudoephedrine products, and actively participated in the unlawful trafficking of this listed chemical knowing that it was being diverted to the manufacture of methamphetamine, as set forth above under factors one and two.

With respect to factor five, such other factors relevant to and consistent with the public safety, the Deputy Administrator finds substantial evidence in the investigative file that the owners of MDI cannot be entrusted with the responsibilities inherent in a DEA registration. Ms. DeLuce and Mr. Uzan distributed large quantities of pseudoephedrine to locations not typically associated with large-scale transactions involving these over-the-counter products (*i.e.,* small retailers of tobacco products). DEA's has obtained information that MDI pseudoephedrine products have been found at numerous clandestine settings.

In light of these events, the Deputy Administrator finds it particularly disturbing that MDI's owners were aware that their pseudoephedrine products were being diverted to illicit uses, but chose to ignore this fact, apparently in the interest of financial gain. Ms. DeLuce and Mr. Uzan were so cavalier and reckless in their quest for profit that they shipped caseloads quantities of pseudoephedrine tablets to non-existent business locations. Such conduct on the part of a DEA registrant is unacceptable, and lends further support to the revocation of a DEA Certificate of Registration.

Ms. DeLuce also demonstrated a lack of candor in her dealings with DEA personnel. On May 24, 2001, Ms. DeLuce informed DEA Diversion Investigators that MDI limited its sale of pseudoephedrine to its customers to one case (or 144 bottles containing 120 tablets) per month. However, Ms. DeLuce's statements are not corroborated by DEA's investigative findings:

The investigative file reveals that in October 2000, MDI sold caseload quantities of pseudoephedrine to Mike's Smoke Shop (2923 North Avenue location) on three occasions; in 2000, during the months of September, November and December, MDI sold caseload quantities to Mike's Smoke Shop (1010½ North 5th Street location) on three separate occasions. In March 2001, MDI shipped caseload quantities of pseudoephedrine to that same location on four occasions; in October 2000, MDI sold caseload quantities of pseudoephedrine to Paradise Smoke, Special Smoke Shop and Special Smoke Shop on four separate occasions for each store. MDI also sold caseload quantities of pseudoephedrine to Special Smoke Shop on four occasions in March 2001, including two caseloads that were sent within two days of one another.

Ms. DeLuce further informed DEA Diversion Investigators that MDI suspended all sales of pseudoephedrine products to any retail establishment affiliated with Suhail Issa and Mike Yako as a result of the aforementioned traffic stop in Colorado. She further represented that the smoke shop establishments operated by Suhail Issa and Mr. Yako in the State of Colorado had closed. Despite Ms. DeLuce's representations, DEA obtained information that MDI continued its sale of pseudoephedrine products to establishments operated by Suhail Issa and Mr. Yako in the State of Colorado following the March 18, 2001, traffic stop. At least three of the transactions took place after Ms. DeLuce provided assurances to DEA personnel that she had discontinued the sale of listed chemicals to Suhail Issa and Mr. Yako.

The Deputy Administrator finds this lack of candor, taken together with the registrant's disregard of laws and regulations pertaining to a DEA registration to distribute listed chemicals, makes questionable MDI and its owners's commitment to the DEA statutory and regulatory requirements designed to protect the public from the diversion of listed chemicals. Seaside Pharmaceutical Co., 67 FR 12580 (2002); Aseel, Incorporated, Wholesale Division, 66 FR 35459 (2001); Terrence E. Murphy, M.D., 61 FR 2841 (1996).

Accordingly, the Deputy Administrator of the Drug Enforcement Administration, pursuant to the authority vested in him by 21 U.S.C. 823 and 824 and 28 CFR 0.100(b) and 0.104, hereby orders that DEA Certificate of Registration, 0046291EY, previously issued to MDI Pharmaceuticals, be, and it hereby is, revoked. The Deputy Administrator further orders that any pending applications for renewal or modification of said registration be, and they hereby are, denied. This order is effective February 27, 2003.

Dated: January 2, 2003.

John B. Brown, III,

Deputy Administrator.

[FR Doc. 03–1915 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–09–M

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

Manufacture of Controlled Substances Notice of Registration

By Notice dated June 18, 2002, and published in the **Federal Register** on

July 10, 2002, (67 FR 45765), Roche Diagnostics Corporation, ATTN: Regulatory Compliance, 9115 Hague Road, Indianapolis, Indiana 46250, made application by renewal to the Drug Enforcement Administration (DEA) to be registered as a bulk manufacturer of the basic classes of controlled substances listed below:

Drug	Schedule
Lysergic acid diethylamide (7315).	I
Tetrahydrocannabinols (7370).	I
Alphamethadol (9605) ..	I
Phencyclidine (7471)	II
Benzoylecgonine (9180)	II
Methadone (9250)	II
Morphine (9300)	II

Roche Diagnostics Corporation plans to manufacture small quantities of the above listed controlled substances for incorporation in drug of abuse detection kits.

No comments or objections have been received. DEA has considered the factors in Title 21, U.S.C., § 823(a) and determined that the registration of Roche Diagnostics Corporation is consistent with the public interest at this time. DEA has investigated Roche Diagnostics Corporation on a regular basis to ensure that the company's continued registration is consistent with the public interest. These investigations have included inspection and testing of the company's physical security systems, audits of the company's records, verification of the company's compliance with state and local laws, and a review of the company's background and history., 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 classes of controlled substances listed above is granted.

Dated: January 6, 2003.

Laura M. Nagel,

Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration.

[FR Doc. 03–1917 Filed 1–27–03; 8:45 am]

BILLING CODE 4410–09–M

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Review; Comment Request

January 17, 2003.

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 (Pub. L. 104–13, 44 U.S.C. Chapter 35). A copy of this ICR, with applicable supporting documentation, may be obtained by calling the Department of Labor. To obtain documentation contact Darrin King on 202–693–4129 or E-Mail: *King-Darrin@dol.gov*.

Comments should be sent to Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for OSHA, 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: Occupational Safety and Health Administration (OSHA).

Type of Review: Extension of a currently approved collection.

Title: Temporary Labor Camps.

OMB Number: 1218–0096.

Affected Public: Business or other for-profit; farms, Federal Government; and State, Local, or Tribal Government.

Frequency: On occasion.

Type of Responses: Reporting.

Number of Respondents: 863.

Annual Responses: 863.

Average Response Time: 5 minutes.

Annual Burden Hours: 69.

Total Annualized Capital/Startup Costs: $0.

Total Annual Costs (operating/maintaining systems or purchasing services): $0.

Description: 29 CFR 1910.142(1) requires temporary labor camp superintendents to report immediately to the local health officer the name and address of any individual in the camp known to have or suspected of having a communicable disease or suspected food poisoning, or an unusual prevalence of any illness in which fever, diarrhea, sore throat, vomiting or jaundice is a prominent symptom. The information is used to limit the incidence of communicable disease among temporary labor camp residence.

Ira L. Mills,

Departmental Clearance Officer.

[FR Doc. 03–1850 Filed 1–27–03; 8:45 am]

BILLING CODE 4510–13–M

DEPARTMENT OF LABOR

Office of the Secretary

Bureau of International Labor Affairs; Request for Information Concerning Labor Rights in Singapore and Its Laws Governing Exploitative Child Labor

AGENCIES: Office of the Secretary, Labor; Office of the United States Trade Representative and Department of State.

ACTION: Request for public comments.

SUMMARY: This notice is a request for public comments to assist the Secretary of Labor, the United States Trade Representative and the Secretary of State in preparing reports regarding labor rights in Singapore and describing the extent to which Singapore has in effect laws governing exploitative child labor. The Trade Act of 2002 requires reports on these issues and others when the President intends to use trade promotion authority procedures in connection with legislation approving and implementing a trade agreement. Negotiators for the United States and Singapore announced that they approved the elements of such an agreement on November 19, 2002. The President assigned the functions of preparing reports regarding labor rights and the existence of laws governing exploitative child labor to the Secretary of Labor, in consultation with the Secretary of State and the United States Trade Representative. The Secretary of Labor further assigned these functions to the Secretary of State and United States Trade Representative.

DATES: Public comments should be received no later than 5 p.m. February 27, 2003.

ADDRESSES: Persons submitting comments are strongly advised to make such submissions by electronic mail to the following address: *FRFTASINGAPORE@dol.gov.* Submissions by facsimile may be sent to: Betsy White at the Office of International Economic Affairs, Bureau of International Labor Affairs (202) 693–4851.

FOR FURTHER INFORMATION CONTACT: For procedural questions regarding the submissions please contact Betsy White, Bureau of International Labor Affairs, Office of International Economic Affairs, at (202) 693–4919, facsimile (202) 693–4851. This is not a toll-free number. Substantive questions concerning the labor rights report and/or the report on Singapore's laws governing exploitative child labor should be addressed to Jorge Perez-Lopez, Office of International Economic Affairs, Bureau of International Labor Affairs, U.S. Department of Labor, 200 Constitution Avenue, NW., Washington, DC 20210, telephone (202) 693–4883.

SUPPLEMENTARY INFORMATION:

I. Background

The Trade Act of 2002 (Pub. L. 107–210) (''the Trade Act'') sets forth special procedures (Trade Promotion Authority) for approval and implementation of Agreements subject to meeting conditions and requirements in the Act. Division B of the Trade Act, entitled the Bipartisan Trade Promotion Authority Act of 2002, includes negotiating objectives and a listing of priorities for the President to promote in order to ''address and maintain United States competitiveness in the global economy'' in pursuing future trade agreements. 19 U.S.C. 3802(a)–(c). The President delegated several of the functions in section 3802(c) to the Secretary of Labor. (E.O. 13277). These include the functions set forth in section 2102(c)(8), which requires that the President ''in connection with any trade negotiations entered into under this Act, submit to the Committee on Ways and Means of the House of Representatives and the Committee on Finance of the Senate a meaningful labor rights report of the country, or countries, with respect to which the President is negotiating * * *'' and the function in section 2102(c)(9), which requires that the President ''with respect to any trade agreement which the President seeks to implement under trade authorities procedures, submit to the Congress a report describing the extent to which the country or countries that are parties to the agreement have in effect laws governing exploitative child labor.''

II. Information Sought

Interested parties are invited to submit written information as specified below to be taken into account in drafting the required reports. Materials submitted should be confined to the specific topics of the reports. In particular, agencies are seeking written submissions on the following topics:

1. Singapore's labor laws, including laws governing exploitative child labor, and Singapore's implementation and enforcement of such laws and regulations;
2. The situation in Singapore with respect to core labor standards;
3. Steps taken by Singapore to comply with International Labor Organization Convention 182 on the worst forms of child labor; and
4. The nature and extent, if any, of exploitative child labor in Singapore.

Section 2113(6) of the Trade Act defines ''core labor standards'' as:

(A) The right of association;

(B) The right to organize and bargain collectively;

(C) A prohibition on the use of any form of forced or compulsory labor;

(D) A minimum age for the employment of children; and

(E) Acceptable conditions of work with respect to minimum wages, hours of work, and occupational safety and health.

III. Requirements for Submissions

To ensure prompt and full consideration of submissions, we strongly recommend that interested persons submit comments by electronic mail to the following e-mail address: *FRFTASINGAPORE@dol.gov.* Persons making submissions by e-mail should use the following subject line: ''Singapore: Labor Rights and Child Labor Reports.'' Documents should be submitted in WordPerfect, MSWord, or text (.TXT) format. Supporting documentation submitted as spreadsheets is acceptable in Quattro Pro or Excel format. Persons who make submissions by e-mail should not provide separate cover letters; information that might appear in a cover letter should be included in the submission itself. Similarly, to the extent possible, any attachments to the submission should be included in the same file as the submission itself, and not as separate files. Written comments will be placed in a file open to public inspection at the Department of Labor, Room S–5317, 200 Constitution Avenue, NW., Washington DC and in the USTR Reading Room in Room 3 of the annex of the Office of the USTR, 1724 F Street, NW., Washington, DC 20508. An appointment to review the file at the Department of Labor may be made by contacting Betsy White at (202) 693–4919. An appointment to review the file at USTR may be made by calling (202) 395–6186. The USTR Reading Room is generally open to the public from 10 a.m.–12 noon and 1–4 p.m. Monday through Friday. Appointments must be scheduled at least 48 hours in advance.

Signed at Washington, DC this 22nd day of January, 2003.

Michael A. Magan,

Associate Deputy Under Secretary for International Affairs.

[FR Doc. 03–1851 Filed 1–27–03; 8:45 am]

BILLING CODE 4510–28–P

DEPARTMENT OF LABOR

Occupational Safety And Health Administration

Advisory Committee on Construction Safety and Health; Notice of Open Meeting

AGENCY: Occupational Safety and Health Administration (OSHA), Labor.

ACTION: Notice of a meeting of the Advisory Committee on Construction Safety and Health (ACCSH).

SUMMARY: ACCSH will meet February 13, 2003, in Rosemont, Illinois. This meeting is open to the public.

TIME AND DATE: ACCSH will meet from 8:30 a.m. to 5 p.m., Thursday, February 13.

PLACE: ACCSH will meet at the Hyatt Regency O'Hare, 9300 West Bryn Mawr Avenue, Rosemont, Illinois.

FOR FURTHER INFORMATION CONTACT: For general information about ACCSH and ACCSH meetings: Jim Boom, OSHA, Directorate of Construction, Room N–3476, U.S. Department of Labor, 200 Constitution Avenue, NW., Washington, DC 20210; telephone 202–693–1839. For information about submission of comments, requests to speak, and the need for accommodations for the meeting: Veneta Chatmon, OSHA, Office of Public Affairs, Room N–3647, U.S. Department of Labor, 200 Constitution Avenue, NW., Washington, DC 20210; telephone 292–693–1999.

Electonic copies of this Federal Register notice, as well as information about ACCSH workgroups and other relevant documents, are available at OSHA's Web page on the Internet at *http://www.osha.gov.*

SUPPLEMENTARY INFORMATION: ACCSH will meet February 13, 2003, in

Rosemont, Illinois. This meeting is open to the public. The agenda for this meeting includes:

- Update Region V—Mike Connors, Regional Administrator
- Remarks by the Assistant Secretary for the Occupational Safety and Health Administration, John L. Henshaw
- Directorate of Construction report
- Highway Work Zone Safety
- Subpart V—Power Transmission and Distribution
- Silica
- Hearing Conservation In Construction
- Assigned Protection Factors for Respirators
- Update—OSHA Training Institute
- Workgroup Reports
- Public Comment (During this period, any member of the public is welcome to address ACCSH about construction-related safety and health issues. See information below to request time to speak at the meeting.)

All ACCSH meetings are open to the public. An official record of the meeting will be available for public inspection at the OSHA Docket Office, Room N–2625, at the address above, telephone (202)–693–2350. Individuals needing special accommodations should contact Ms. Chatmon no later than February 3, 2003, at the address above.

Interested parties may submit written data, views or comments, preferably with 20 copies, to Ms. Chatmon, at the address above. OSHA will provide submissions received prior to the meeting to ACCSH members and will include each submission in the record of the meeting. Attendees may also request to make an oral presentation by notifying Veneta Chatmon before the meeting at the address above. The request must state the amount of time desired, the interest represented by the presenter (*e.g.*, the names of the business, trade association, government Agency), if any, and a brief outline of the presentation. The Chair of ACCSH may grant the request at his discretion and as time permits.

Authority: John L. Henshaw, Assistant Secretary of Labor for Occupational Safety and Health, directed the preparation of this notice under the authority granted by section 7 of the Occupational Safety and Health Act of 1970 (29 U.S.C. 656) section 107 of the Contract Work Hours and Safety Standards Act (Construction Safety Act) (40 U.S.C. 333), and Secretary of Labor's Order No. 5–2002 (67 FR 65008).

Signed at Washington, DC, this 21st day of January, 2003.

John L. Henshaw,

Assistant Secretary of Labor.

[FR Doc. 03–1852 Filed 1–27–03; 8:45 am]

BILLING CODE 4510–26–M

LEGAL SERVICES CORPORATION

Sunshine Act Meeting of the Board of Directors Committee on Provision for the Delivery of Legal Services

TIME AND DATE: The Committee on Provision for the Delivery of Legal Services of the Legal Services Corporation Board of Directors will meet on January 31, 2003. The meeting will begin at 9:00 a.m. and continue until the Committee concludes its agenda.

LOCATION: The Washington Court Hotel, 525 New Jersey Avenue, NW., Washington, DC.

STATUS OF MEETING: Open.

MATTERS TO BE CONSIDERED:

1. Approval of agenda.
2. Approval of the minutes of the Committee's meeting of November 8, 2002.
3. *Strategic Directions 2002–2005:* Submission of the 2002 Progress Report for Programs by Randi Youells, Vice President for Programs.
4. Perspectives on GIS Mapping:

(a) Office of the Inspector General's report on the Mapping Evaluation—Legal Services in Georgia, by Leonard Koczur, David Maddox, and Ed Jurkevics.

(b) Report by Michael Genz and Glenn Rawdon of the Office of Program Performance (OPP) on LSC Technology Grants Designed to Enable Grantees to Use GIS Mapping in a Cost-Effective Manner.

5. *The State Planning Evaluation Instrument:* Design and Implementation Panel of Design Team Members with Bob Gross (OPP Senior Counsel), Bob Clyde (Executive Director, Ohio Legal Aid Foundation), Judge Juanita Bing Newton (Deputy Chief Administrative Judge for Justice Initiatives State of New York Unified Court System), and Neal Dudovitz (Executive Director, Neighborhood Legal Services of Los Angeles County).
6. The LSC Diversity Training Module/Next Steps Panel with Pat Hanrahan (Special Counsel to the Vice President for Programs), Wilhelm Joseph (Executive Director, Legal Aid Bureau, Inc.), and Gurdon H. Buck (Board Chair, Statewide Legal Services of Connecticut, Inc.).
7. Consider and act on other business.
8. Public comment.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, Vice President for Legal Affairs, General Counsel & Corporate Secretary, at (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 Elizabeth S. Cushing, at (202) 336–8800.

Dated: January 23, 2003.

Victor M. Fortuno,

Vice President for Legal Affairs, General Counsel and Corporate Secretary.

[FR Doc. 03–1989 Filed 1–24–03; 8:45 am]

BILLING CODE 7050–01–P

LEGAL SERVICES CORPORATION

Sunshine Act Meeting of the Board of Directors Operations and Regulations Committee

TIME AND DATE: The Operations and Regulations Committee of the Legal Services Corporation Board of Directors will meet on January 31, 2003. The meeting will begin at 1:00 p.m. and continue until the Committee concludes its agenda.

LOCATION: The Washington Court Hotel, 525 New Jersey Avenue, NW., Washington, DC.

STATUS OF MEETING: Open.

MATTERS TO BE CONSIDERED:

1. Approval of agenda.
2. Approval of the minutes of the Committee's meeting of November 8, 2002.
3. Consider and act on a draft Final Rule on 45 CFR Part 1611 (Financial Eligibility).
4. Consider and act on a draft Final Rule on 45 CFR Part 1602 (Procedure for Disclosure of Information under the Freedom of Information Act).
5. Consider and act on a draft Final Rule on 45 CFR Part 1604 (Outside Practice of Law).
6. Consider and act on issues relating to open rulemaking on 45 CFR Part 1626 (Restrictions on Legal Assistance to Aliens).
7. Staff report on Limited English Proficiency guidance notice and request for comments.
8. Consider and act on other business.
9. Public comment.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, Vice President for Legal Affairs, General Counsel & Corporate Secretary, at (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 Elizabeth S. Cushing, at (202) 336–8800.

Dated: January 23, 2003.

Victor M. Fortuno,

Vice President for Legal Affairs, General Counsel and Corporate Secretary.

[FR Doc. 03–1990 Filed 1–24–03; 8:45 am]

BILLING CODE 7050–01–P

LEGAL SERVICES CORPORATION

Sunshine Act Meeting of the Board of Directors Finance Committee

TIME AND DATE: The Finance Committee of the Legal Services Corporation Board of Directors will meet on January 31, 2003. The meeting will begin at 3:15 p.m. and continue until the Committee concludes its agenda.

LOCATION: The Washington Court Hotel, 525 New Jersey Avenue, NW, Washington, DC.

STATUS OF MEETING: Open.

MATTERS TO BE CONSIDERED:

1. Approval of agenda.
2. Approval of the minutes of the Committee's meeting of November 8, 2002.
3. Report on LSC's Temporary Operating Budget, Expenses and Other Funds Available through December 31, 2002.
4. Consider and act on amendments to the 403(b) Thrift Plan for Employees of LSC.
5. Consider and act on amendments to LSC's Flexible Spending Account.
6. Consider and act on other business.
7. Public comment.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, Vice President for Legal Affairs, General Counsel & Corporate Secretary, at (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 Elizabeth S. Cushing, at (202) 336–8800.

Dated: January 23, 2003.

Victor M. Fortuno,

Vice President for Legal Affairs, General Counsel & Corporate Secretary.

[FR Doc. 03–1991 Filed 1–24–03; 8:45 am]

BILLING CODE 7050–01–P

LEGAL SERVICES CORPORATION

Sunshine Act Meeting of the Board of Directors

TIME AND DATE: The Board of Directors of the Legal Services Corporation will meet on February 1, 2003. The meeting will begin at 9 a.m. and continue until conclusion of the Board's agenda.

LOCATION: The Washington Court Hotel, 525 New Jersey Avenue, NW, Washington, DC.

STATUS OF MEETING: Open, except that a portion of the meeting may be closed pursuant to a vote of the Board of Directors to hold an executive session. At the closed session, the Corporation's 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 is authorized by the relevant provisions of the Government in the Sunshine Act [5 U.S.C. 552b(c) (10)] and the corresponding provisions of the Legal Services Corporation's implementing regulation [45 CFR 1622.5(h)]. A copy of the General Counsel's Certification that the closing is authorized by law will be available upon request.

MATTERS TO BE CONSIDERED:

Open Session

1. Approval of agenda.
2. Approval of the minutes of the Board's meeting of November 9, 2002.
3. Approval of the minutes of the Executive Session of the Board's meeting of November 9, 2002.
4. Approval of the Board's Special Session on Strategic Directions meeting of November 8, 2002.
5. Approval of the Board's telephonic meeting of November 25, 2002.
6. Chairman's Report.
7. Members' Report.
8. Acting Inspector General's Report.
9. President's Report.
10. Consider and act on the report of the Board's Committee on Provision for the Delivery of Legal Services.
11. Consider and act on the report of the Board's Operations and Regulations Committee.
12. Consider and act on the report of the Board's Finance Committee.
13. Consider and act on the Board's 2002 Annual Performance Reviews Committee's report on the annual evaluation of the Corporation's President and Acting Inspector General.
14. Consider and act on possible dissolution of the Board's 2002 Annual Performance Reviews Committee.
15. Consider and act on contract renewals for LSC Vice Presidents Randi Youells, Mauricio Vivero, and Victor Fortuno.
16. Consider and act on the Board's 2003 meeting schedule.

Closed Session

17. Briefing [1] by the Inspector General on the activities of the Office of Inspector General.
18. Consider and act on the Office of Legal Affairs' report on potential and pending litigation involving LSC.

Open Session

19. Consider and act on other business.
20. Public Comment.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, Vice President for Legal Affairs, General Counsel & Secretary of the Corporation, at (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 Elizabeth S. Cushing, at (202) 336–8800.

Dated: January 23, 2003.

Victor M. Fortuno,

Vice President for Legal Affairs, General Counsel & Corporate Secretary.

[FR Doc. 03–1992 Filed 1–24–03; 8:45 am]

BILLING CODE 7050–01–P

LEGAL SERVICES CORPORATION

Sunshine Act Meeting of the Board of Directors Ad Hoc Committee on Performance Reviews of the President and Inspector General

TIME AND DATE: The Ad Hoc Committee on Performance Reviews of the President and Acting Inspector General of the Legal Services Corporation's Board of Directors will meet on January 31, 2003. The meeting will begin at 4:30 p.m. and continue until conclusion of the committee's agenda.

LOCATION: The Washington Court Hotel, 525 New Jersey Avenue, NW, Washington, DC.

STATUS OF MEETING: Except for approval of the committee's agenda and any miscellaneous business that may come before the committee, the meeting will be closed to the public. The closing is authorized by the relevant provisions of the Government in the Sunshine Act [5 U.S.C. 552b(c)(2) & (6)] and the corresponding provisions of the Legal Services Corporation's implementing regulation [45 CFR 1622.5(a) & (e)]. A copy of the General Counsel's Certification that the closing is authorized by law will be available upon request.

MATTERS TO BE CONSIDERED:

[1] Any portion of the closed session consisting solely of staff briefings does not fall within the Sunshine Act's definition of the term ''meeting'' and, therefore, the requirements of the Sunshine Act do not apply to any such portion of the closed session. 5 U.S.C. 552(b)(a)(2) and (b). See also 45 CFR § 1622.2 & 1622.3

Open Session

1. Approval of agenda.
2. Approval of the minutes of the Committee's meeting of November 9, 2002.

Closed Session

3. Consider and act on recommendations to the Board of Directors on the annual evaluation of the President for FY 2002.
4. Consider and act on recommendations to the Board of Directors on the annual evaluation of the Acting Inspector General for FY 2002.

Open Session

5. Consider and act on other business.
6. Public comment.

CONTACT PERSON FOR INFORMATION: Victor M. Fortuno, Vice President for Legal Affairs, General Counsel and Corporate Secretary, at (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 Elizabeth S. Cushing at (202) 336–8800.

Dated: January 23, 2003.

Victor M. Fortuno,

Vice President for Legal Affairs, General Counsel, and Corporate Secretary.

[FR Doc. 03–1993 Filed 1–24–03; 8:45 am]

BILLING CODE 7050–01–P

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

Meetings of Humanities Panel

AGENCY: The National Endowment for the Humanities.

ACTION: Additional notice of meetings.

SUMMARY: Pursuant to the provisions of the Federal Advisory Committee Act (Pub. L. 92–463, as amended), notice is hereby given that the following meetings of the Humanities Panel will be held at the Old Post Office, 1100 Pennsylvania Avenue, NW., Washington, DC 20506.

FOR FURTHER INFORMATION CONTACT: Daniel Schneider, Advisory Committee Management Officer, National Endowment for the Humanities, Washington, DC 20506; telephone (202) 606–8322. Hearing-impaired individuals are advised that information on this matter may be obtained by contacting the Endowment's TDD terminal on (202) 606–8282.

SUPPLEMENTARY INFORMATION: The proposed meetings are for the purpose of panel review, discussion, evaluation and recommendation on applications for financial assistance 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 the grant applicants. Because the proposed meetings will consider information that is likely to disclose trade secrets and commercial or financial information obtained from a person and privileged or confidential and/or information of a personal nature the disclosure of which would constitute a clearly unwarranted invasion of personal privacy, pursuant to authority granted me by the Chairman's Delegation of Authority to Close Advisory Committee meetings, dated July 19, 1993, I have determined that these meetings will be closed to the public pursuant to subsections (c) (4), and (6) of section 552b of title 5, United States Code.

1. *Date:* February 6, 2003.

Time: 8:30 a.m. to 5 p.m.

Room: 415.

Program: This meeting will review applications for Humanities Projects in Media, submitted to the Division of Public Programs at the November 1, 2002, deadline.

Daniel Schneider,

Advisory Committee, Management Officer.

[FR Doc. 03–1892 Filed 1–27–03; 8:45 am]

BILLING CODE 7536–01–P

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

Meeting of the National Museum Services Board

AGENCY: Institute of Museum and Library Services.

ACTION: Notice of meeting.

SUMMARY: This notice sets forth the agenda of a forthcoming meeting of the National Museum Services Board. This notice also describes the function of the board. Notice of this meeting is required under the Sunshine in Government Act and regulations of the Institute of Museum and Library Services, 45 CFR 1180.84.

Time/Date: 9 a.m.–12 p.m. on Thursday, January 30, 2003.

Status: Open.

ADDRESSES: The JW Marriott Hotel, Salon J and K, 1331 Pennsylvania Avenue, NW., Washington, DC, (202) 393–2000.

FOR FURTHER INFORMATION CONTACT: Elizabeth Lyons, Special Assistant to the Director, Institute of Museum and Library Services, 1100 Pennsylvania Avenue, NW., Room 510, Washington, DC 20506, (202) 606–4649.

SUPPLEMENTARY INFORMATION: The National Museum Services Board is established under the Museum Services Act, Title II of the Arts, Humanities, and Cultural Affairs Act of 1976, Public Law 94–462. The Board has responsibility for the general policies with respect to the powers, duties, and authorities vested in the Institute under the Museum Services Act.

The meeting on Thursday, January 30, 2003 will be open to the public. If you need special accommodations due to a disability, please contact: Institute of Museum and Library Services, 1100 Pennsylvania Avenue, NW., Washington, DC 20506–(202) 606–8536–TDD (202) 606–8636 at least seven (7) days prior to the meeting date.

Agenda

86th Meeting of the National Museum Services Board in Salon J and K of The JW Marriott Hotel, 1331 Pennsylvania Avenue, NW., Washington, DC, on Thursday, January 30, 2003.

9 am–12 pm

I. Chairperson's Welcome

II. Approval of Minutes from the 85th NMSB Meeting

III. Director's Welcome and Remarks

IV. Overview of the President's Committee on the Arts and Humanities, *Henry Moran, Executive Director*

V. Staff Updates

VI. 21st Century Learner Dialogue

(a) Presentation, *Beverly Sheppard, President of Oil Sturbridge Village*

(b) Service Organization Response, *Ed Able, President and CEO, American Association of Museums Janet Rice Elman, Executive Director, Association of Children's Museums*

VII. Status of Museum/School Partnership

VIII. Board Discussion

IX. Closing Remarks

Dated: January 23, 2003.

Teresa LaHaie,

Administration Officer, National Foundation on the Arts and Humanities, Institute of Museum and Library Services.

[FR Doc. 03–2011 Filed 1–24–03; 11:17 am]

BILLING CODE 7036–01–M

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50–335 and 389]

Saint Lucie Nuclear Plant; Notice of Consideration of Issuance of Amendments to Facility Operating License, Proposed No Significant Hazards Consideration Determination, and Opportunity for a Hearing

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of amendments to Facility Operating License Nos. DPR–67 and NPF–16, issued to Florida Power & Light (FPL) for operation of the Saint Lucie Units 1 and 2 located in Saint Lucie County, Florida. The proposed amendments would revise the Technical Specifications (TS) section 5.6, ''Design Features—Fuel Storage,'' to include the design of a new cask pit spent fuel storage rack for each unit to increase the allowable spent fuel wet storage capacity at both units and include the description of Boral ™ as the neutron absorbing material used in the new cask pit storage racks. The proposal also revises the spent fuel pool (SFP) thermal-hydraulic analyses for core offload times of 120 hours after reactor shutdown and for a partial core offload as the normal offload condition. In addition the proposal includes a change in FPL's commitments regarding the Unit 2 spent fuel cooling system design basis described in the Updated Final Safety Analysis Report (UFSAR). A current UFSAR commitment regarding the Unit 2 peak SFP temperature limit during full core offloads with minimum SFP cooling will be replaced with a new design basis.

The Commission has made a proposed determination that the amendment request involves no significant hazards consideration. Under the Commission's regulations in title 10 of the Code of Federal Regulations (10 CFR), section 50.92, this means that operation of the facility in accordance with the proposed amendment would not (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration, which is presented below:

1. Would operation of the facility in accordance with the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

No. The proposed change to increase the spent fuel storage capacity with cask area racks was evaluated for impact on the following previously evaluated events:

a. A fuel handling accident (FHA)
b. A heavy load drop into the cask area
c. A loss of SFP cooling
d. A stored fuel criticality event
e. A seismic event

The probability of a fuel handling accident is not significantly increased by the proposed change, because the same equipment (*e.g.*, the spent fuel handling machine) and procedures will be used to handle fuel assemblies and the frequency of fuel movement will be essentially the same, with or without cask area racks. The FHA radiological consequences are not significantly increased because the source term of a single fuel assembly will remain unchanged, and the cask area racks will be installed at the same water depth as the existing SFP racks, with the same iodine decontamination factors assumed in the FHA analysis. The structural consequences of dropping a fuel assembly on a cask area rack were also found to be no more severe than those in the current FHA analysis.

The probability and consequences of a heavy load drop of the cask area rack are bounded by the existing cask drop analyses. The consequences are not adversely affected because a fuel transfer cask is much heavier than the empty rack. The probability of such an event is not adversely affected because adding a cask area rack will postpone the need for cask handling operations by extending the spent fuel storage. The cask area rack will be removed prior to any cask handling operations, such that a cask drop scenario onto a cask area rack loaded with fuel is not credible. Therefore, the probability and the consequences of a heavy load drop in the cask area are not significantly increased.

The probability of a loss of SFP cooling is unaffected and its consequences are not significantly increased with cask area racks installed. The addition of a cask area rack has an insignificant impact on the total SFP decay heat load. With the cask area rack installed, loss of forced cooling results in a sufficient time-to-boil for the operator to recognize the condition and establish SFP makeup to compensate for water lost due to pool bulk boiling, and thereby maintain a sufficient water blanket over the stored spent fuel.

The probability and consequences of a stored fuel criticality event are not increased by the addition of a cask area rack. The reactivity analysis for the new racks demonstrates the storage configuration remains subcritical for the worst-case fuel mispositioning event, with credit for soluble boron.

The probability of a seismic event is unaffected and its consequences are not significantly increased with cask area racks installed, because the structural analysis of the new racks demonstrates that the fuel storage function of the rack is unimpaired by loading combinations including seismic motion, and there is no adverse seismic-induced interaction between the rack and adjacent structures.

Based on the above, it is concluded that the proposed amendments do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Would operation of the facility in accordance with the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

No. The proposed change to add a cask area rack to each unit does not alter the equipment credited in the mitigation of design basis accidents, nor does the proposed change affect any of the important parameters required to ensure the safe storage of spent fuel. A new rack material (Boral™) is introduced into the pool under this change, but based on its operating history in SFPs, there are no mechanisms that create a new or different kind of accident.

The potential for dropping the new rack during installation or removal is bounded by the existing analysis for dropping a spent fuel transfer cask into the cask area. The same equipment (*e.g.*, the spent fuel handling crane) and procedures will be used to handle fuel assemblies for the new cask area racks as are used for existing spent fuel storage. The fuel storage configuration in the new racks will be similar to the configuration in the existing SFP storage racks, and a fuel drop or mispositioning event in the new racks does not represent a new or different kind of accident from fuel handling and mispositioning events previously evaluated. Therefore, the proposed amendments will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Would operation of the facility in accordance with the proposed amendment involve a significant reduction in a margin of safety?

No. The effect of the proposed change on current margins of safety was evaluated for spent fuel storage functionality and criticality, spent fuel and SFP cooling, and structural integrity of the spent fuel pool. The design of the new racks uses proven technology which preserves the proper safety margins for spent fuel storage to provide a coolable and subcritical geometry under both normal and abnormal/accident conditions. The design complies with current regulatory guidelines and the ANSI [American National Standards Institute] standards, including 10 CFR 50 Appendix A General Design Criterion (GDC) 62, NUREG–0800 section 9.1.2, the OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications, Regulatory Guide 1.13, and ANSI/ANS [American Nuclear Society] 8.17. Handling the racks in accordance with the defense-in-depth approach of NUREG–0612 with temporary lift items designed to ANSI N14.6 preserves the proper margin of safety to preclude a heavy load drop in the cask area.

The cask area rack criticality analysis demonstrates that the neutron multiplication factor is maintained below 1.0, without credit for soluble boron, and less than or equal to 0.95 when credit is taken for the 650 ppm [parts per million] of soluble boron required

for the existing SFP storage racks. The structural analyses for the new racks and adjacent structures show that the rack and surrounding structures are unimpaired by loading combinations during seismic motion, and there is no adverse seismic-induced interaction between the rack and adjacent racks or structures. Based on these evaluations, operating the facility with the proposed amendments do not involve a significant reduction in any margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the amendment request involves no significant hazards consideration.

The Commission is seeking public comments on this proposed determination. Any comments received within 30 days after the date of publication of this notice will be considered in making any final determination.

Normally, the Commission will not issue the amendments until the expiration of the 30-day notice period. However, should circumstances change during the notice period such that failure to act in a timely way would result, for example, in derating or shutdown of the facility, the Commission may issue the license amendments before the expiration of the 30-day notice period, provided that its final determination is that the amendments involve no significant hazards consideration. The final determination will consider all public and State comments received. Should the Commission take this action, it will publish in the **Federal Register** a notice of issuance and provide for opportunity for a hearing after issuance. The Commission expects that the need to take this action will occur very infrequently.

Written comments may be submitted by mail to the Chief, Rules and Directives Branch, Division of Administrative Services, Office of Administration, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, and should cite the publication date and page number of this **Federal Register** notice. Written comments may also be delivered to Room 6D59, Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, from 7:30 a.m. to 4:15 p.m. Federal workdays. Documents may be examined, and/or copied for a fee, at the NRC's Public Document Room (PDR), located at One White Flint North, Public Fire Area O1–F21, 11555 Rockville Pike (first floor), Rockville, Maryland.

The filing of requests for hearing and petitions for leave to intervene is discussed below.

By February 27, 2003, the licensee may file a request for a hearing with respect to issuance of the amendment to the subject facility operating license and any person whose interest may be affected by this proceeding and who wishes to participate as a party in the proceeding must file a written request for a hearing and a petition for leave to intervene. Requests for a hearing and a petition for leave to intervene shall be filed in accordance with the Commission's ''Rules of Practice for Domestic Licensing Proceedings'' in 10 CFR part 2. Interested persons should consult a current copy of 10 CFR 2.714,[1] which is available at the Commission's PDR, located at One White Flint North, Public File Area 01–F21, 11555 Rockville Pike, Rockville, Maryland, or electronically on the Internet at the NRC Web site *http://www.nrc.gov/reading-rm/doc-collections/cfr/*. If there are problems in accessing the document, contact the PDR Reference staff at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr@nrc.gov.* If a request for a hearing or petition for leave to intervene is filed by the above date, the Commission or an Atomic Safety and Licensing Board, designated by the Commission or by the Chairman of the Atomic Safety and Licensing Board Panel, will rule on the request and/or petition; and the Secretary or the designated Atomic Safety and Licensing Board will issue a notice of hearing or an appropriate order.

As required by 10 CFR 2.714, a petition for leave to intervene shall set forth with particularity the interest of the petitioner in the proceeding, and how that interest may be affected by the results of the proceeding. The petition should specifically explain the reasons why intervention should be permitted with particular reference to the following factors: (1) The nature of the petitioner's right under the Act to be made party to the proceeding; (2) the nature and extent of the petitioner's property, financial, or other interest in the proceeding; and (3) the possible effect of any order which may be entered in the proceeding on the petitioner's interest. The petition should also identify the specific aspect(s) of the subject matter of the proceeding as to which petitioner wishes to intervene.

Any person who has filed a petition for leave to intervene or who has been admitted as a party may amend the petition without requesting leave of the Board up to 15 days prior to the first prehearing conference scheduled in the proceeding, but such an amended petition must satisfy the specificity requirements described above.

Not later than 15 days prior to the first prehearing conference scheduled in the proceeding, a petitioner shall file a supplement to the petition to intervene which must include a list of the contentions which are sought to be litigated in the matter. Each contention must consist of a specific statement of the issue of law or fact to be raised or controverted. In addition, the petitioner shall provide a brief explanation of the bases of the contention and a concise statement of the alleged facts or expert opinion which support the contention and on also provide references to those specific sources and documents of which the petitioner is aware and on which the petitioner intends to rely to establish those facts or expert opinion. Petitioner must provide sufficient information to show that a genuine dispute exists with the applicant on a material issue of law or fact. Contentions shall be limited to matters within the scope of the amendment under consideration. The contention must be one which, if proven, would entitle the petitioner to relief. A petitioner who fails to file such a supplement which satisfies these requirements with respect to at least one contention will not be permitted to participate as a party.

Those permitted to intervene become parties to the proceeding, subject to any limitations in the order granting leave to intervene, and have the opportunity to participate fully in the conduct of the hearing, including the opportunity to present evidence and cross-examine witnesses.

If a hearing is requested, the Commission will make a final determination on the issue of no significant hazards consideration. The final determination will serve to decide when the hearing is held.

If the final determination is that the amendment request involves no significant hazards consideration, the Commission may issue the amendment and make it immediately effective, notwithstanding the request for a hearing. Any hearing held would take place after issuance of the amendment.

If the final determination is that the amendment request involves a significant hazards consideration, any hearing held would take place before the issuance of any amendment.

[1] The most recent version of title 10 of the Code of Federal Regulations, published January 1, 2002, inadvertently omitted the last sentence of 10 CFR 2.714(d) and subparagraphs (d)(1) and (2), regarding petitions to intervene and contentions. For the complete, corrected text of 10 CFR 2.714(d), please *see* 67 FR 20884 (April 29, 2002).

A request for a hearing or a petition for leave to intervene must be filed with the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemakings and Adjudications Staff, or may be delivered to the Commission's PDR, located at One White Flint North, Public File Area O1–F21, 11555 Rockville Pike, Rockville, Maryland, by the above date. Because of the continuing disruptions in delivery of mail to United States Government offices, it is requested that petitions for leave to intervene and requests for hearing be transmitted to the Secretary of the Commission either by means of facsimile transmission to 301–415–1101 or by e-mail to *hearingdocket@nrc.gov.* A copy of the petition for leave to intervene and request for hearing should also be sent to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, and because of continuing disruptions in delivery of mail to United States Government offices, it is requested that copies be transmitted either by means of facsimile transmission to 301–415–3725 or by e-mail to *OGCMailCenter@nrc.gov.* A copy of the request for hearing and petition for leave to intervene should also be sent to M.S. Ross, Attorney, Florida Power & Light, P.O. Box 14000, Juno Beach, Florida 33408–0420, attorney for the licensee.

Nontimely filings of petitions for leave to intervene, amended petitions, supplemental petitions and/or requests for hearing will not be entertained absent a determination by the Commission, the presiding officer or the presiding Atomic Safety and Licensing Board that the petition and/or request should be granted based upon a balancing of the factors specified in 10 CFR 2.714(a)(1)(i)–(v) and 2.714(d).

The Commission hereby provides notice that this is a proceeding on an application for a license amendment falling within the scope of section 134 of the Nuclear Waste Policy Act of 1982 (NWPA), 42 U.S.C. 10154. Under section 134 of the NWPA, the Commission, at the request of any party to the proceeding, must use hybrid hearing procedures with respect to ''any matter which the Commission determines to be in controversy among the parties.''

The hybrid procedures in section 134 provide for oral argument on matters in controversy, preceded by discovery under the Commission's rules and the designation, following argument of only those factual issues that involve a genuine and substantial dispute, together with any remaining questions of law, to be resolved in an adjudicatory hearing. Actual adjudicatory hearings are to be held on only those issues found to meet the criteria of section 134 and set for hearing after oral argument.

The Commission's rules implementing section 134 of the NWPA are found in 10 CFR part 2, subpart K, ''Hybrid Hearing Procedures for Expansion of Spent Fuel Storage Capacity at Civilian Nuclear Power Reactors'' (published at 50 FR 41662 dated October 15, 1985). Under those rules, any party to the proceeding may invoke the hybrid hearing procedures by filing with the presiding officer a written request for oral argument under 10 CFR 2.1109. To be timely, the request must be filed within 10 days of an order granting a request for hearing or petition to intervene. The presiding officer must grant a timely request for oral argument. The presiding officer may grant an untimely request for oral argument only upon a showing of good cause by the requesting party for the failure to file on time and after providing the other parties an opportunity to respond to the untimely request. If the presiding officer grants a request for oral argument, any hearing held on the application must be conducted in accordance with the hybrid hearing procedures. In essence, those procedures limit the time available for discovery and require that an oral argument be held to determine whether any contentions must be resolved in an adjudicatory hearing. If no party to the proceeding timely requests oral argument, and if all untimely requests for oral argument are denied, then the usual procedures in 10 CFR part 2, subpart G apply.

For further details with respect to this action, see the application for amendment dated October 23, 2002, which is available for public inspection at the Commission's PDR, located at One White Flint North, Public File Area O1–F21, 11555 Rockville Pike, Rockville, Maryland. Publicly available records will be accessible from the Agencywide Documents Access and Management System's (ADAMS) Public Electronic Reading Room on the Internet at the NRC Web site, *http://www.nrc.gov/reading-rm/adams.html.* Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS should contact the NRC PDR Reference staff by telephone at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr@nrc.gov.*

Dated in Rockville, Maryland, this 22nd day of January, 2003.

For the Nuclear Regulatory Commission.

Brendan T. Moroney,

Project Manager, Section 2, Project Directorate II, Division of Licensing Project Management, Office of Nuclear Reactor Regulation.

[FR Doc. 03–1858 Filed 1–27–03; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50–250 and 251]

Turkey Point Plant; Notice of Consideration of Issuance of Amendments to Facility Operating License, Proposed No Significant Hazards Consideration Determination, and Opportunity for a Hearing

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of amendments to Facility Operating License Nos. DPR–31 and DPR–41, issued to Florida Power & Light, for operation of the Turkey Point Plant, Units 3 and 4 located in Miami-Dade County, Florida.

The proposed amendments would increase the total spent fuel wet storage capacity for each unit, by adding a spent fuel storage rack in the cask area in each unit's spent fuel pool (SFP). Each rack will increase the respective unit's storage capacity by 131 fuel assemblies. The proposed license amendments also revise the location called out in the Design Features sections 5.6.1.1a and b of the Technical Specifications referring to Updated Final Safety Analysis Report Appendix 14D rather than referring to Westinghouse Report WCAP–14416–P.

Before issuance of the proposed license amendments, the Commission will have made findings required by the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations.

The Commission has made a proposed determination that the amendment request involves no significant hazards consideration. Under the Commission's regulations in title 10 of the Code of Federal Regulations (10 CFR), § 50.92, this means that operation of the facility in accordance with the proposed amendment would not (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant

hazards consideration, which is presented below:

1. Would operation of the facility in accordance with the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

No. The proposed change to increase the spent fuel storage capacity with cask area racks was evaluated for impact on the following previously evaluated events:

a. A fuel handling accident (FHA)
b. A heavy load drop into the cask area
c. A loss of SFP cooling
d. A stored fuel criticality event
e. A seismic event

The probability of a fuel handling accident is not significantly increased by the proposed change, because the same equipment (*e.g.*, the spent fuel handling machine) and procedures will be used to handle fuel assemblies and the frequency of fuel movement will be essentially the same, with or without cask area racks. The FHA radiological consequences are not significantly increased because the source term of a single fuel assembly will remain unchanged, and the cask area racks will be installed at the same water depth as the existing SFP racks, with the same iodine decontamination factors assumed in the FHA analysis. The structural consequences of dropping a fuel assembly on a cask area rack were also found to be no more severe than those in the current FHA analysis.

The probability and consequences of a heavy load drop of the cask area rack are bounded by the existing cask drop analyses. The consequences are not adversely affected because a fuel transfer cask is much heavier than the empty rack. The probability of such an event is not adversely affected because adding a cask area rack will postpone the need for cask handling operations by extending the spent fuel storage. The cask area rack will be removed prior to any cask handling operations, such that a cask drop scenario onto a cask area rack loaded with fuel is not credible. Therefore, the probability and the consequences of a heavy load drop in the cask area are not significantly increased.

The probability of a loss of SFP cooling is unaffected and its consequences are not significantly increased with cask area racks installed. The addition of a cask area rack has an insignificant impact on the total SFP decay heat load. With the cask area rack installed, loss of forced cooling results in a sufficient time-to-boil for the operator to recognize the condition and establish SFP makeup to compensate for water lost due to pool bulk boiling, and thereby maintain a sufficient water blanket over the stored spent fuel.

The probability and consequences of a stored fuel criticality event are not increased by the addition of a cask area rack. The reactivity analysis for the new racks demonstrates the storage configuration remains subcritical for the worst-case fuel mispositioning event, with credit for soluble boron.

The probability of a seismic event is unaffected and its consequences are not significantly increased with cask area racks installed, because the structural analysis of the new racks demonstrates that the fuel storage function of the rack is unimpaired by loading combinations including seismic motion, and there is no adverse seismic-induced interaction between the rack and adjacent structures.

Based on the above, it is concluded that the proposed amendments do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Would operation of the facility in accordance with the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

No. The proposed change to add a cask area rack to each unit does not alter the equipment credited in the mitigation of design basis accidents, nor does the proposed change affect any of the important parameters required to ensure the safe storage of spent fuel. A new rack material (Boral™) is introduced into the pool under this change, but based on its operating history in SFPs, there are no mechanisms that create a new or different kind of accident.

The potential for dropping the new rack during installation or removal is bounded by the existing analysis for dropping a spent fuel transfer cask into the cask area. The same equipment (*e.g.*, the spent fuel handling crane) and procedures will be used to handle fuel assemblies for the new cask area racks as are used for existing spent fuel storage. The fuel storage configuration in the new racks will be similar to the configuration in the existing SFP storage racks, and a fuel drop or mispositioning event in the new racks does not represent a new or different kind of accident from fuel handling and mispositioning events previously evaluated. Therefore, the proposed amendments will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Would operation of the facility in accordance with the proposed amendment involve a significant reduction in a margin of safety?

No. The effect of the proposed change on current margins of safety was evaluated for spent fuel storage functionality and criticality, spent fuel and SFP cooling, and structural integrity of the spent fuel pool. The design of the new racks uses proven technology which preserves the proper safety margins for spent fuel storage to provide a coolable and subcritical geometry under both normal and abnormal/accident conditions. The design complies with current regulatory guidelines and the ANSI [American National Standards Institute] standards, including 10 CFR 50 Appendix A General Design Criterion (GDC) 62, NUREG–0800 section 9.1.2, the OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications, Regulatory Guide 1.13, and ANSI/ANS [American Nuclear Society] 8.17. Handling the racks in accordance with the defense-in-depth approach of NUREG–0612 with temporary lift items designed to [American National Standards Institute] ANSI N14.6 preserves the proper margin of safety to preclude a heavy load drop in the cask area.

The cask area rack criticality analysis demonstrates that the neutron multiplication factor is maintained below 1.0, without credit for soluble boron, and less than or equal to 0.95 when credit is taken for the 650 ppm [parts per million] of soluble boron required for the existing SFP storage racks. The structural analyses for the new racks and adjacent structures show that the rack and surrounding structures are unimpaired by loading combinations during seismic motion, and there is no adverse seismic-induced interaction between the rack and adjacent racks or structures. Based on these evaluations, operating the facility with the proposed amendments do not involve a significant reduction in any margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the amendment request involves no significant hazards consideration.

The Commission is seeking public comments on this proposed determination. Any comments received within 30 days after the date of publication of this notice will be considered in making any final determination.

Normally, the Commission will not issue the amendments until the expiration of the 30-day notice period. However, should circumstances change during the notice period such that failure to act in a timely way would result, for example, in derating or shutdown of the facility, the Commission may issue the license amendments before the expiration of the 30-day notice period, provided that its final determination is that the amendments involve no significant hazards consideration. The final determination will consider all public and State comments received. Should the Commission take this action, it will publish in the **Federal Register** a notice of issuance and provide for opportunity for a hearing after issuance. The Commission expects that the need to take this action will occur very infrequently.

Written comments may be submitted by mail to the Chief, Rules and Directives Branch, Division of Administrative Services, Office of Administration, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, and should cite the publication date and page number of this **Federal Register** notice. Written comments may also be delivered to Room 6D59, Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, from 7:30 a.m. to 4:15 p.m. Federal workdays. Documents may be examined, and/or copied for a fee, at the NRC's Public

Document Room (PDR), located at One White Flint North, Public File Area O1–F21, 11555 Rockville Pike, Rockville, Maryland.

The filing of requests for hearing and petitions for leave to intervene is discussed below.

By February 27, 2003, the licensee may file a request for a hearing with respect to issuance of the amendment to the subject facility operating license and any person whose interest may be affected by this proceeding and who wishes to participate as a party in the proceeding must file a written request for a hearing and a petition for leave to intervene. Requests for a hearing and a petition for leave to intervene shall be filed in accordance with the Commission's ''Rules of Practice for Domestic Licensing Proceedings'' in 10 CFR part 2. Interested persons should consult a current copy of 10 CFR 2.714,[1] which is available at the Commission's PDR, located at One White Flint North, Public File Area O1–F21, 11555 Rockville Pike, Rockville, Maryland, or electronically on the Internet at the NRC Web site *http://www.nrc.gov/reading-rm/doc-collections/cfr/.* If there are problems in accessing the document, contact the Public Document Room Reference staff at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr@nrc.gov.* If a request for a hearing or petition for leave to intervene is filed by the above date, the Commission or an Atomic Safety and Licensing Board designated by the Commission or by the Chairman of the Atomic Safety and Licensing Board Panel will rule on the request and/or petition; and the Secretary or the designated Atomic Safety and Licensing Board will issue a notice of hearing or an appropriate order.

As required by 10 CFR 2.714, a petition for leave to intervene shall set forth with particularity the interest of the petitioner in the proceeding, and how that interest may be affected by the results of the proceeding. The petition should specifically explain the reasons why intervention should be permitted with particular reference to the following factors: (1) The nature of the petitioner's right under the Act to be made party to the proceeding; (2) the nature and extent of the petitioner's property, financial, or other interest in the proceeding; and (3) the possible effect of any order which may be entered in the proceeding on the petitioner's interest. The petition should also identify the specific aspect(s) of the subject matter of the proceeding as to which petitioner wishes to intervene. Any person who has filed a petition for leave to intervene or who has been admitted as a party may amend the petition without requesting leave of the Board up to 15 days prior to the first prehearing conference scheduled in the proceeding, but such an amended petition must satisfy the specificity requirements described above.

Not later than 15 days prior to the first prehearing conference scheduled in the proceeding, a petitioner shall file a supplement to the petition to intervene which must include a list of the contentions which are sought to be litigated in the matter. Each contention must consist of a specific statement of the issue of law or fact to be raised or controverted. In addition, the petitioner shall provide a brief explanation of the bases of the contention and a concise statement of the alleged facts or expert opinion which support the contention and on which the petitioner intends to rely in proving the contention at the hearing. The petitioner must also provide references to those specific sources and documents of which the petitioner is aware and on which the petitioner intends to rely to establish those facts or expert opinion. Petitioner must provide sufficient information to show that a genuine dispute exists with the applicant on a material issue of law or fact. Contentions shall be limited to matters within the scope of the amendment under consideration. The contention must be one which, if proven, would entitle the petitioner to relief. A petitioner who fails to file such a supplement which satisfies these requirements with respect to at least one contention will not be permitted to participate as a party.

Those permitted to intervene become parties to the proceeding, subject to any limitations in the order granting leave to intervene, and have the opportunity to participate fully in the conduct of the hearing, including the opportunity to present evidence and cross-examine witnesses.

If a hearing is requested, the Commission will make a final determination on the issue of no significant hazards consideration. The final determination will serve to decide when the hearing is held.

If the final determination is that the amendment request involves no significant hazards consideration, the Commission may issue the amendment and make it immediately effective, notwithstanding the request for a hearing. Any hearing held would take place after issuance of the amendment.

If the final determination is that the amendment request involves a significant hazards consideration, any hearing held would take place before the issuance of any amendment.

A request for a hearing or a petition for leave to intervene must be filed with the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemakings and Adjudications Staff, or may be delivered to the Commission's PDR, located at One White Flint North, Public File Area O1–F21, 11555 Rockville Pike, Rockville, Maryland, by the above date. Because of the continuing disruptions in delivery of mail to United States Government offices, it is requested that petitions for leave to intervene and requests for hearing be transmitted to the Secretary of the Commission either by means of facsimile transmission to 301–415–1101 or by e-mail to *hearingdocket@nrc.gov.* A copy of the petition for leave to intervene and request for hearing should also be sent to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, and because of continuing disruptions in delivery of mail to United States Government offices, it is requested that copies be transmitted either by means of facsimile transmission to 301–415–3725 or by e-mail to *OGCMailCenter@nrc.gov.* A copy of the request for hearing and petition for leave to intervene should also be sent to M.S. Ross, Attorney, Florida Power & Light, P.O. Box 14000, Juno Beach, Florida 33408–0420, attorney for the licensee.

Nontimely filings of petitions for leave to intervene, amended petitions, supplemental petitions and/or requests for hearing will not be entertained absent a determination by the Commission, the presiding officer or the presiding Atomic Safety and Licensing Board that the petition and/or request should be granted based upon a balancing of the factors specified in 10 CFR 2.714(a)(1)(i)–(v) and 2.714(d).

The Commission hereby provides notice that this is a proceeding on an application for a license amendment falling within the scope of section 134 of the Nuclear Waste Policy Act of 1982 (NWPA), 42 U.S.C. 10154. Under section 134 of the NWPA, the Commission, at the request of any party to the proceeding, must use hybrid hearing procedures with respect to ''any matter which the Commission determines to be in controversy among the parties.''

[1] The most recent version of title 10 of the Code of Federal Regulations, published January 1, 2002, inadvertently omitted the last sentence of 10 CFR 2.714(d) and subparagraphs (d)(1) and (2), regarding petitions to intervene and contentions. For the complete, corrected text of 10 CFR 2.714(d), please see 67 FR 20884 (April 29, 2002).

The hybrid procedures in section 134 provide for oral argument on matters in controversy, preceded by discovery under the Commission's rules and the designation, following argument of only those factual issues that involve a genuine and substantial dispute, together with any remaining questions of law, to be resolved in an adjudicatory hearing. Actual adjudicatory hearings are to be held on only those issues found to meet the criteria of section 134 and set for hearing after oral argument.

The Commission's rules implementing section 134 of the NWPA are found in 10 CFR part 2, subpart K, ''Hybrid Hearing Procedures for Expansion of Spent Fuel Storage Capacity at Civilian Nuclear Power Reactors' (published at 50 FR 41662 dated October 15, 1985). Under those rules, any party to the proceeding may invoke the hybrid hearing procedures by filing with the presiding officer a written request for oral argument under 10 CFR 2.1109. To be timely, the request must be filed within 10 days of an order granting a request for hearing or petition to intervene. The presiding officer must grant a timely request for oral argument. The presiding officer may grant an untimely request for oral argument only upon a showing of good cause by the requesting party for the failure to file on time and after providing the other parties an opportunity to respond to the untimely request. If the presiding officer grants a request for oral argument, any hearing held on the application must be conducted in accordance with the hybrid hearing procedures. In essence, those procedures limit the time available for discovery and require that an oral argument be held to determine whether any contentions must be resolved in an adjudicatory hearing. If no party to the proceeding timely requests oral argument, and if all untimely requests for oral argument are denied, then the usual procedures in 10 CFR part 2, subpart G apply.

For further details with respect to this action, *see* the application for amendment dated November 26, 2002, which is available for public inspection at the Commission's PDR, located at One White Flint North, Public File Area O1–F21, 11555 Rockville Pike, Rockville, Maryland. Publicly available records will be accessible from the Agencywide Documents Access and Management System's (ADAMS) Public Electronic Reading Room on the Internet at the NRC Web site, *http://www.nrc.gov/reading-rm/adams.html.* Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS should contact the NRC PDR Reference staff by telephone at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr@nrc.gov.*

Dated in Rockville, Maryland, this 21st day of January, 2003.

For the Nuclear Regulatory Commission.

Eva A. Brown,

Project Manager, Section 2, Project Directorate II, Division of Licensing Project Management, Office of Nuclear Reactor Regulation.

[FR Doc. 03–1861 Filed 1–27–03; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50–277 and 50–278]

Exelon Generating Company, LLC; Peach Bottom Atomic Power Station, Units 2 and 3; Notice of Availability of the Final Supplement 10 to the Generic Environmental Impact Statement Regarding License Renewal for the Peach Bottom Atomic Power Station, Units 2 and 3

Notice is hereby given that the U.S. Nuclear Regulatory Commission (NRC) has published a final plant-specific Supplement 10 to the Generic Environmental Impact Statement (GEIS), NUREG–1437, regarding the renewal of operating licenses DPR–44 and DPR–56 for the Peach Bottom Atomic Power Station, Units 2 and 3, for an additional 20 years of operation. The Peach Bottom Atomic Power Station units are operated by Exelon Generating Company, LLC and PSEG Nuclear, LLC (Exelon). Peach Bottom Atomic Power Station is located primarily in Peach Bottom Township, York County, Pennsylvania. Possible alternatives to the proposed action (license renewal) include no action and reasonable alternative methods of power generation.

It is stated in section 9.3 of the report:

> Based on (1) the analysis and findings in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants, NUREG–1437; (2) the Environmental Report submitted by Exelon; (3) consultation with Federal, State, and local agencies; (4) the staff's own independent review; and (5) the staff's consideration of public comments, the staff recommends that the Commission determine that the adverse environmental impacts of license renewal for Peach Bottom Units 2 and 3 are not so great that preserving the option of license renewal for energy planning decision makers would be unreasonable.

The final Supplement 10 to the GEIS is available electronically for public inspection in the NRC Public Document Room (PDR) located at One White Flint North, 11555 Rockville Pike (first floor), Rockville, Maryland, or from the Publicly Available Records (PARS) component of NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at *http://www.nrc.gov* (the Public Electronic Reading Room). Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS, should contact the PDR reference staff at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr@nrc.gov.*

FOR FURTHER INFORMATION CONTACT: Mr. Louis L. Wheeler, License Renewal and Environmental Impacts Program, Division of Regulatory Improvement Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555. Mr. Wheeler may be contacted at 301–415–1444 or by writing to: Louis L. Wheeler, U.S. Nuclear Regulatory Commission, MS O–12D3, Washington, DC 20555.

Dated in Rockville, Maryland, this 22nd day of January, 2003.

For the Nuclear Regulatory Commission.

Pao-Tsin Kuo,

Program Director, License Renewal and Environmental Impacts Program, Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation.

[FR Doc. 03–1859 Filed 1–27–03; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 030–33507]

Research Medical Center Environmental Assessment and Finding of No Significant Impact; Exemption

The U.S. Nuclear Regulatory Commission is authorizing Research Medical Center, License No. 24–17998–02, an exemption to 10 CFR 35.615(f)(3), to permit the licensee to have a neurosurgeon physically present in place of an authorized user during the use of its gamma stereotactic radiosurgery unit.

Environmental Assessment

Identification of the Proposed Action

Research Medical Center has a United States Nuclear Regulatory Commission (NRC) license (License No. 24–17998–02) that authorizes the use of a gamma stereotactic radiosurgery (GSR) unit. The licensee has requested, in a letter dated September 20, 2002, that the NRC grant an exemption to 10 CFR 35.615(f)(3), which requires an authorized user and authorized medical

physicist to be physically present throughout all patient treatments with the GSR unit. This requirement became effective on October 24, 2002.

Research Medical Center has requested the exemption to allow a neurosurgeon to replace an authorized user if the following criteria is met: the neurosurgeon has received at least one full week of training at a formal training course for GSRs, including operation and emergency response; the neurosurgeon is working under the authorized user's supervision, and the neurosurgeon will be physically present in place of the authorized user once the treatment has been initiated. During patient treatment with the GSR unit, the authorized user will be immediately available and the substitution will not average more than 50% of the time. The authorized medical physicist will be present throughout all patient treatments.

Need for the Proposed Action

The exemption is needed so that Research Medical Center can continue to provide optimum medical treatment to its patients. The licensee indicates that without the exemption to 10 CFR 35.516(f)(3), GSR procedures would have to be periodically interrupted whenever it would be necessary to call the authorized user to attend to other responsibilities in the Radiation Oncology Department, which would not be conducive to timely completion of the procedure. The licensee states further that neurosurgeons are in large part responsible for the care of patients undergoing GSR, have completed the same course in GSR as the authorized users and are fully capable of handling any medical emergency, and are present during at least part of the treatment, and that the Radiation Oncology Department is separated from the GSR by a short enough distance such that an authorized user could respond quickly if necessary.

Environmental Impacts of the Proposed Action

The GSR sources are sealed sources and no material will be released into the environment. All the sources are contained within the unit, as verified by periodic spot checks performed by the licensee. The proposed action does not increase public radiation exposure. There will be no impact on the environment as a result of the proposed action.

Alternatives to the Proposed Action

As required by section 102(2)(E) of NEPA (42 U.S.C. 4322(2)(E)), possible alternatives to the final action have been considered. The alternatives are: (1) To deny the exemption request or (2) to require the licensee to provide another alternative method as a basis for granting the exemption. The alternative options would not produce a gain in protecting the human environment, and would negatively impact the licensee implementation of medical care to patients.

Alternative Use of Resources

No alternative use of resources was considered due to the reasons stated above.

Agencies and Persons Consulted

This proposed action was discussed with the State of Missouri.

Identification of Source Used

Letter from Research Medical Center, to U.S. Nuclear Regulatory Commission, Region III, dated September 20, 2002.

Finding of No Significant Impact

Based on the above environmental assessment, the Commission has concluded that the proposed action will not have a significant effect on the quality of the human environment. Accordingly, the NRC has determined that a finding of no significant impact is appropriate and preparation of an environmental impact statement is not warranted.

The licensee's letter is available for inspection, and/or copying for a fee, in the Region III Public Document Room, 801 Warrensville Road, Lisle, IL 60532. The document is available electronically for public inspection from the Publically Available Records (PARS) component of NRC's Documents Access and Management System (ADAMS), accession number ML030220477. ADAMS is accessible from the NRC Web site at *http://www.nrc.gov/reading-rm/adams.html.*

Dated in Rockville, Maryland, this 22nd day of January, 2003.

For the Nuclear Regulatory Commission.

Frederick Brown,

Section Chief, Material Safety and Inspection Branch, Division of Industrial and Medical Nuclear Safety, Office of Nuclear Material Safety and Safeguards.

[FR Doc. 03–1860 Filed 1–27–03; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Sunshine Act Meeting

AGENCY: Nuclear Regulatory Commission.

DATE: Weeks of January 27, February 3, 10, 17, 24, March 3, 2003.

PLACE: Commissioners' Conference Room, 11555 Rockville Pike, Rockville, Maryland.

STATUS: Public and closed.

MATTERS TO BE CONSIDERED:

Week of January 27, 2003

There are no meetings scheduled for the Week of January 27, 2003.

Week of February 3, 2003—Tentative

Tuesday, February 4, 2003

2 p.m.—Briefing on Lessons Learned: Davis-Besse Reactor Vessel Head (RVH) Degradation (Public Meeting) (Contact: Stacey Rosenberg, 301–415–1733)

This meeting will be webcast live at the Web address—*www.nrc.gov*

Wednesday, February 5, 2003

1 p.m.—Discussion of Governmental Issues (Closed—Ex. 1 & 9)

Week of February 10, 2003—Tentative

Monday, February 20, 2003

10 a.m.—Briefing on Status of Office of Nuclear Reactor Regulation (NRR) Programs, Performance, and Plans (Public Meeting) (Contract: Michael Case, 301–415–1275)

The meeting will be webcast live at the Web address—*www.nrc.gov*

Tuesday, February 11, 2003

10 a.m.—Briefing on Status of Office of the Chief Financial Officer (OCFO) Programs, Performance, and Plans (Public meeting) (Contact: Patrice Williams-Johnson, 301–415–5732)

This meeting will be webcast live at the Web address—*www.nrc.gov.*

Week of February 17, 2003—Tentative

There are no meetings scheduled for the Week of February 17, 2003.

Week of February 24, 2003—Tentative

Monday, February 24, 2003

2 p.m.—Meeting with National Association of Regulatory Utility Commissioners (NARUC) (Public Meeting)

This meeting will be webcast live at the Web address—*www.nrc.gov*

Week of March 3, 2003

Monday, March 3, 2003

10 a.m.—Briefing on Status of Office of Nuclear Material Safety and Safeguards (NMSS) Programs—Waste Safety (Public Meeting) (Contact: Claudia Seelig, 301–415–7243)

This meeting will be webcast live at the Web address—*www.nrc.gov*

*The schedule for Commission meetings is subject to change on short

notice. To verify the status of meetings call (recording)—(301) 415–1292. Contact person for more information: David Louis Gamberoni (301) 415–1651.

Additional Information

''Briefing on Status of Office of the Chief Information Officer (OCIO) Programs, Performance, and Plans,'' originally scheduled for February 4, 2003, has been canceled.

By a vote of 5–0 on January 22, the Commission determined pursuant to U.S.C. 552b(e) and § 9.107(a) of the Commission's rules that ''Affirmation of Pacific Gas & Electric Co. (Diablo Canyon Power Plant Independent Spent Fuel Storage Installation); Licensing Board's referral in LBP–02–23 of its denial to admit terrorism contentions/issues'' be held on January 23, and on less than one week's notice to the public.

The NRC Commission Meeting Schedule can be found on the Internet at: *www.nrc.gov/what-we-do/policy-making/schedule.html*

This notice is distributed by mail to several hundred subscribers; if you no longer wish to receive it, or would like to be added to the distribution, please contact the Office of the Secretary, Washington, DC 20555 (301–415–1969). In addition, distribution of this meeting notice over the Internet system is available. If you are interested in receiving this Commission meeting schedule electronically, please send an electronic message to *dkw@nrc.gov.*

Dated: January 23, 2003.

David Louis Gamberoni,

Technical Coordinator, Office of the Secretary.

[FR Doc. 03–2040 Filed 1–24–03; 2:00 pm]

BILLING CODE 7590–01–M

POSTAL SERVICE BOARD OF GOVERNORS

Sunshine Act Meeting

Times and Dates: 12:30 p.m., Monday, February 3, 2003; 8:30 a.m., Tuesday, February 4, 2003.

Place: Las Vegas, Nevada, at the Four Seasons Hotel, 3960 Las Vegas Boulevard South, in the Four Seasons Ballroom 4.

Status: February 3—12:30 p.m. (Closed); February 4—8:30 a.m. (Open).

Matters To Be Considered:

Monday, February 3—12:30 p.m. (Closed)

1. Financial Performance.
2. Rate Case Planning.
3. Strategic Planning.
4. Personnel Matters and Compensation Issues.

Tuesday, February 4—8:30 a.m. (Open)

1. Minutes of the Previous Meeting, January 6–7, 2003.
2. Remarks of the Postmaster General and CEO.
3. Appointment of Members to Board Committees.
4. Corporate Flats Strategy.
5. Capital Investment.
   a. Labor Scheduler—Phase 1.
6. Pacific Area and Nevada-Sierra District Report.
7. Tentative Agenda for the March 3–4, 2003, meeting in Washington, DC.

FOR FURTHER INFORMATION CONTACT: William T. Johnstone, Secretary of the Board, U.S. Postal Service, 475 L'Enfant Plaza, SW., Washington, DC 20260–1000. Telephone (202) 268–4800.

William T. Johnstone,

Secretary.

[FR Doc. 03–2050 Filed 1–24–03; 2:14 pm]

BILLING CODE 7710–12–M

SECURITIES AND EXCHANGE COMMISSION

[Release No. IC–25908: File No. 812–12837]

The Travelers Insurance Company, et al.

January 21, 2003.

AGENCY: Securities and Exchange Commission (''SEC'' or ''Commission'').

ACTION: Notice of application for an order pursuant to section 11(a) of the Investment Company Act of 1940 (''1940 Act'' or ''Act'') approving the terms of an offer of exchange.

Applicants: The Travelers Insurance Company (''Travelers Insurance''), The Travelers Life and Annuity Company (''Travelers Life''), The Travelers Fund U for Variable Annuities (''Fund U''), The Travelers Separate Account Five for Variable Annuities (''Account Five''), The Travelers Separate Account Six for Variable Annuities (''Account Six''), Travelers Growth and Income Stock Account (''Account GIS''), Travelers Money Market Account (''Account MM''), Travelers Quality Bond Account (''Account QB''), Travelers Timed Aggressive Stock Account (''Account TAS''), Travelers Timed Growth and Income Stock Account (''Account TGIS''), Travelers Timed Short-Term Bond Account (''Account TSB''), and Travelers Distribution LLC (''Travelers Distribution'') (Fund U, Account GIS, Account MM, Account QB, Account TAS, Account TGIS, and Account TSB, collectively, ''UA Accounts'') (Account Five and Account Six, collectively (''TRA Accounts'') (Travelers Insurance, Travelers Life, UA Accounts, TRA Accounts, and Travelers Distribution, collectively, the ''Applicants'').

SUMMARY: Applicants seek an order pursuant to section 11(a) of the Act approving the terms of a proposed offer of exchange. Under the terms of the proposed exchange, certain contract owners of Universal Annuity contracts offered by Travelers Insurance (the ''UA contracts'') through the UA Accounts would be offered the opportunity to exchange their variable annuity contracts for the Travelers Retirement Account annuity contracts (the ''TRA contracts'') offered by Travelers Insurance and Travelers Life through the TRA Accounts.

DATES: The application was filed on June 17, 2002, and amended and restated on December 4, 2002.

Hearing or Notification of Hearing: An order granting the application will be issued unless the Commission orders a hearing. Interested persons may request a hearing by writing to the Secretary of the Commission and serving Applicants with a copy of the request, personally or by mail. Hearing requests should be received by the Commission by 5:30 p.m. on February 14, 2003, and should be accompanied by proof of service on 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. Persons may request notification of a hearing by writing to the Secretary of the Commission.

ADDRESSES: Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609. Applicants, Kathleen A. McGah, Esq., The Travelers Insurance Company, One Tower Square, Hartford, CT 06183.

FOR FURTHER INFORMATION CONTACT: Leland B. Erickson, Staff Attorney, or Zandra Y. Bailes, Branch Chief, Office of Insurance Products, Division of Investment Management, at (202) 942–0670.

SUPPLEMENTARY INFORMATION: The following is a summary of the application. The complete application is available for a fee from the Commission's Public Reference Branch, 450 Fifth Street, NW., Washington, DC 20549–0102 (telephone (202) 942–8090).

Applicants' Representations

1. Travelers Insurance is a stock insurance company. It is licensed to conduct life insurance business in all fifty states, the District of Columbia, Puerto Rico, Guam, the U.S. Virgin

Islands, the British Virgin Islands, and the Bahamas. Travelers Insurance is an indirect wholly owned subsidiary of Citigroup Inc.

2. Travelers Life is a stock insurance company. It is licensed to conduct life insurance business in a majority of the states of the United States, the District of Columbia, and Puerto Rico, and intends to seek licensure in the remaining states, except New York. Travelers Life is an indirect wholly owned subsidiary of Citigroup Inc.

3. Travelers Insurance established Fund U as a separate account on May 16, 1983. Fund U is divided into subaccounts, 35 of which are offered in the UA contracts. Fund U is registered with the Commission as a unit investment trust under the 1940 Act.[1]

4. Travelers Insurance established Accounts GIS, QB, MM, TGIS, TSB and TAS as managed separate accounts on the following dates: Account GIS—September 22, 1967; Account QB—July 29, 1974; Account MM—December 29, 1981, Accounts TGIS and TSB—October 30, 1986; and Account TAS—January 2, 1987. Each managed separate account is registered with the Commission as a diversified open-end management investment company under the 1940 Act.[2]

5. Travelers Insurance established Account Five as a separate account on June 6, 1998. Account Five is divided into subaccounts, 61 of which are offered in the TRA contracts. Account Five is registered with the Commission as a unit investment trust under the 1940 Act.[3]

6. Travelers Life established Account Six on June 6, 1998. Account Six is divided into subaccounts, 61 of which are offered in the TRA contracts. Account Six is registered with the Commission as a unit investment trust under the 1940 Act.[4]

7. Under Connecticut law, the assets of each respective separate account (''Account'') attributable to the Contracts are owned either by Travelers Insurance or Travelers Life, but are held separately from the other assets of Travelers Insurance or Travelers Life for the benefit of the owners of, and the persons entitled to payment under those contracts. Income, gains and losses, whether or not realized, from the assets of each Account are credited to or charged against that Account without regard to the other income, gains, or losses of Travelers Insurance or Travelers Life. In addition, the assets of any such Account equal to the reserves and other contract liabilities with respect to that Account are not chargeable with liabilities arising out of any other business Travelers Insurance or Travelers Life may conduct.

8. Travelers Distribution is registered as a broker-dealer under the Securities Exchange Act of 1934 (''1934 Act'') and is a member of the NASD. Travelers Distribution serves as the principal underwriter for the UA and TRA contracts, and is affiliated with Travelers Insurance and Travelers Life.

9. Each contract is a flexible premium variable annuity contract. Travelers Insurance registered the UA contracts under the Securities Act of 1933 on Form N–4 (File No. 2–79529); Travelers Insurance and Travelers Life registered the TRA contracts under the Securities Act of 1933 on Form N–4 (File Nos. 333–58783 (Account Five) and 333–58809 (Account Six)).[5] Each contract may be used in connection with certain types of retirement plans that receive favorable treatment under the Internal Revenue Code of 1986, as amended, (the ''Code'') (''Qualified Contracts''), and the UA contract may be issued to an owner who is not purchasing the contract for use in such tax-favorable retirement plans (''Non-Qualified Contracts''). Each contract provides for the accumulation of values on a variable basis, fixed basis, or both, during the accumulation period, and provides for settlement or annuity payment options on a variable or fixed basis.

Universal Annuity Contract

10. Travelers Insurance issues the UA contract to individuals or groups.[6] An owner may purchase a UA contract for a minimum initial payment of $1,000 for a Non-Qualified Contract or an IRA contract ($20 for a Qualified Contract), and submit additional payments of $100 ($20 for a Qualified Contract) thereafter.

11. An owner may allocate his or her payments to and transfer cash value among the variable funding options and the Fixed Account (where the current interest rate is 3.5%). The variable funding options include six managed separate accounts (Account GIS, Account MM, Account QB, Account TAS, Account TGIS, and Account TSB) and one UIT/separate account, Fund U. Fund U has 34 subaccounts that are available for investment by UA owners. Each subaccount of Fund U invests in shares of a fund or portfolio of a mutual fund.

12. An owner may transfer all or a portion of his or her investment between and among the UA Accounts and the Fixed Account and may make transfers between the Fixed Account and the VA Accounts. Certain limitations, however, may apply. Travelers Insurance currently does not charge for such transfers, but reserves the right to assess such a charge in the future.

13. An owner may elect to enter into a separate advisory agreement with CitiStreet Financial Services LLC (''CitiStreet''), an affiliate of Travelers Insurance and Travelers Life and an investment adviser registered under the Investment Company Act of 1940. For a fee, CitiStreet provides asset allocation advice under either its CHART Program® or its Tactical Asset Allocation Program. Under the CHART Program®, CitiStreet will allocate all of an owner's purchase payments among the CitiStreet Funds available in the UA Contract. Under the Tactical Asset Allocation Program, CitiStreet will transfer an owner's contract value among TGIS, TSB and TAS (the ''Market Timed Accounts''). An owner also may invest in the Market Timed Accounts through an asset allocation program of an adviser not affiliated with Travelers Insurance, subject to the approval of Traveler's Insurance; and an owner may invest in those Accounts without the assistance of an investment adviser. However, if an owner invests in the Market Timed Accounts without a tactical asset allocation agreement, he or she may bear a higher proportion of the expenses associated with separate account portfolio turnover.

14. A UA owner may surrender his or her UA contract or make a withdrawal of that contract's cash surrender value at any time before the contract's maturity date. In addition, an owner may take withdrawals using a systematic withdrawal program. An owner may instruct Travelers Insurance to calculate and make the minimum distributions that may be required by the Internal Revenue Service upon the owner's reaching age 70½.

15. There are various charges and deductions made under the UA contract. Travelers Insurance assesses a mortality and expense risk charge against the assets of the managed separate accounts and Fund U in an amount, computed daily, at an annual

[1] File No. 811–3575.

[2] File No. 811–1539 (Account GIS); File No. 811–2571 (Account QB); File No. 811–3409 (Account MM); File No. 811–5090 (Account TGIS); File No. 811–5089 (Account TSB); and File No. 811–5091 (Account TAS).

[3] File No. 811–08867.

[4] File No. 811–08869.

[5] There is a market value adjustment feature under the TRA contract. Each Company registered this feature with the Commission on Form S–2 under the Securities Act of 1933 (File Nos. 333–69793 (Travelers Insurance) and 333–69753 (Travelers Life).

[6] For the purposes of this notice, the term ''contract'' includes a certificate under a group contract, and the term ''owner'' includes participant under a group contract.

rate of 1.25% of the daily net asset value of those Accounts. Travelers Insurance also assesses a semiannual contract administrative charge of $15.

16. Travelers Insurance assesses charges for certain transactions an owner may make under the UA contract. If an owner surrenders his contract or takes a withdrawal, Travelers Insurance may assess a contingent deferred sales charge of 5% of the payment surrendered or withdrawn if the owner surrenders or withdraws the payment within five years of the payment's date. However, beginning in the second contract year, the owner may withdraw up to 10% of the cash value of his or her contract annually without Travelers Insurance assessing the contingent deferred sales charge. Travelers Insurance also reserves the right to assess a transfer charge on transfers an owner may make among the investments options available in the UA contract.

17. Each underlying fund and managed separate account has its own fees and expenses. Total annual operating expenses for the variable funding options range from .26% to 2.11% (based on the average daily net assets of the funding option, after expense reimbursement, as of December 31, 2001). Some of the underlying funds charge a 12b–1 fee against their assets. The total annual operating expenses for the Market Timed Accounts include market timing fees equal on an annual basis to 1.25% of the current value of the assets participating in the Tactical Asset Allocation program with CitiStreet. Travelers Insurance deducts this fee daily from the assets of the Market Timed Accounts. CitiStreet also charges a $30 Tactical Asset Allocation application fee.

18. Travelers Insurance will deduct charges for any premium tax or other tax levied by any governmental entity from payments or cash value at death, surrender or annuitization, but no earlier than the time the contract incurs the tax.

19. If the owner or annuitant dies before an UA contract's maturity date, Travelers Insurance will pay the beneficiary a death benefit. The amount paid on the death of the annuitant depends on the age of the annuitant at death. If the annuitant dies on or after age 75, Travelers Insurance will pay the beneficiary the cash value of the contract. If the Annuitant dies before age 75, and before the maturity date, Travelers Insurance will pay the beneficiary the greater of: (a) Cash value; (b) total purchase payments made; or (c) the cash value on the most recent 5th multiple contract year anniversary less any withdrawals made since that anniversary before Travelers Insurance receives proof of death. If an owner who is not the annuitant dies before the maturity date, Travelers Insurance will pay the beneficiary the cash value of the contract. If any owner or annuitant dies on or after the maturity date, Travelers Insurance will pay the beneficiary any benefit remaining under the annuity or income option then in effect.

20. If the annuitant is living on the maturity date, Travelers Insurance will pay the owner or his or her designated payee annuity or income payments beginning on that date. These payments may be in a single lump-sum payment, under five annuity options (*i.e.*, payments made based on the life of the annuitant), under three income options (*i.e.*, payments made for a fixed time not based on the life of the annuitant), or under any other mutually agreed upon annuity option. The owner may choose whether he or she would like all or part of his or her annuity payments to be made on a fixed or variable basis.

TRA Contract

21. Travelers Insurance and Travelers Life (depending on the state where the owner purchases the contract) issue the TRA contract to individuals or groups. An owner may purchase a TRA contract for a minimum initial payment of $20,000 and submit additional payments of $5,000 thereafter. Travelers Insurance/Travelers Life will add a purchase payment credit to each purchase payment that an owner makes if that owner elects the optional death benefit. Each company funds the purchase payment credits from the assets of its general account. The companies assess a higher mortality and expense risk charge for the optional death benefit, but will not require the owner to repay the amount of purchase payment credit to the relevant company should the owner surrender after the ''right to return'' period or take a withdrawal from his or her contract. Specifically, during the ''right to return'' period, a TRA owner who surrenders and who elects the optional death benefit will receive either purchase payments or contract value, depending on applicable state law; the owner will not bear any contract fees associated with the purchase payment credits. Should the owner exercise his or her ''right to return'' rights, the owner will be in the same position as if he or she had exercised the ''right to return'' right in a variable annuity contract that did not have purchase payment credits. The owner would, however, receive any gains, and the relevant company would bear any losses attributable to the purchase payment credits.

22. An owner may allocate his or her payments to and transfer cash value among the variable funding options and the Fixed Account (where the current interest rate is 4% annually). Account Five and Account Six offer the same underlying fund options; each separate account has 61 subaccounts that are available for investment by TRA contract owners. These subaccounts invest in shares of a fund or portfolio of a mutual fund.

23. Subject to certain restrictions, an owner may transfer all or a portion of his or her investment between and among the subaccounts and the Fixed Account and between the Fixed Account and the subaccounts. Travelers Insurance and Travelers Life currently do not charge for transfers, but reserve the right to assess a transfer charge of up to $10 on transfers exceeding 12 per year.

24. An owner may elect to enter into a separate advisory agreement with CitiStreet. For a fee, CitiStreet provides asset allocation advice under its CHART Program®.

25. A TRA owner may surrender his or her TRA contract or make a withdrawal of that contract's cash value at any time before the contract's maturity date. In addition, an owner may take withdrawals using a systematic withdrawal program. An owner also may choose to participate in the Managed Distribution Program, under which the owner may instruct Travelers Insurance/Travelers Life to calculate and make the minimum distributions that may be required by the Internal Revenue Service upon the owner's reaching age 70½.

26. There are various charges and deductions made under the TRA contract. Travelers Insurance/Travelers Life assesses a mortality and expense risk charge against the assets of Account Five/Account Six in an amount, computed daily, at an annual rate of .80% of the daily net asset value if the owner elects the standard death benefit, or 1.25%, if the owner elects the optional death benefit.

27. Travelers Insurance/Travelers Life will assess charges for certain transactions an owner may make under the TRA contract. If an owner surrenders his contract or makes a withdrawal, Travelers Insurance/Travelers Life may assess a withdrawal charge if the owner surrenders or withdraws the payment within five years of when the owner made that payment.

The charge is a percentage of the purchase payment and any applicable

purchase payment credits withdrawn as follows:

Years since purchase payment made	Withdrawal charge (in percent)
0–1	5
2	4
3	3
4	2
5	1
6 or more	0

However, subject to the provisions of the Code, an owner may withdraw up to 20% of the contract value of his or her contract annually without Travelers Insurance/Travelers Life assessing the withdrawal charge.

28. In addition, should a group contract owner surrender its TRA contract (other than because of plan termination due to the dissolution or liquidation of the employer under U.S. Code Title 11 procedures), or should Travelers Insurance/Travelers Life discontinue the TRA contract, Travelers Insurance/Travelers Life will assess a market value adjustment on any contract value held in the Fixed Account. The market value adjustment will reflect the relationship between the interest rate credited to amounts in the Fixed Account at the time of termination and the interest rate credited on new deposits in the Fixed Account at the time of termination.

29. Each underlying fund has its own fees and expenses. Total annual operating expenses for the variable funding options range from .40% to 1.72% (based on the average daily net assets of the funding option, after expense reimbursement, as of December 31, 2001). Some of the underlying funds charge a 12b–1 fee against their assets.

30. Should an owner elect to participate in the CHART® program, the owner will be charged for the investment advisory services CitiStreet provides. This charge is equal to a maximum of .80% of the assets subject to the CHART® Program, and will be paid by quarterly withdrawals from the contract value allocated to the asset allocation funds.

31. As discussed below, Travelers Insurance/Travelers Life offers a Variable Annuitization Floor Benefit. If the owner elects this option during the annuitization period, Travelers Insurance/Travelers Life will deduct a charge upon election; the charge will vary based on market conditions, but will never increase an owner's annual separate account charge by more than 3%. An owner also may elect a liquidity benefit on certain options during the annuitization period (as discussed below). If the owner elects the liquidity benefit and takes a withdrawal, Travelers Insurance/Travelers Life will charge a surrender charge of 5% on the amounts withdrawn.

32. If the owner or annuitant dies before a TRA contract's maturity date, Travelers Insurance/Travelers Life will pay the beneficiary a death benefit. The amount paid on death of the annuitant depends on the age of the annuitant on the contract date and the death benefit option selected. Under the standard death benefit, if the annuitant's age on the contract date was less than age 80, Travelers Insurance/Travelers Life will pay the beneficiary the greater of contract value or the total purchase payments made less any withdrawals (and related charges). If the annuitant's age on the contract date equaled or was greater than age 80, Travelers Insurance/Travelers Life will pay the beneficiary contract value.

33. Under the optional death benefit, if the annuitant's age on the contract date was less than age 70, Travelers Insurance/Travelers Life will pay the beneficiary the greater of contract value, total purchase payments less any withdrawals (and related charges), or maximum step-up value (described below) associated with contract date anniversaries beginning with the 5th and ending with the last before the annuitant's 76th birthday. If the annuitant's age on the contract date was between 70 to 75, Travelers Insurance/Travelers Life will pay the beneficiary the greater of contract value, total purchase payments less any withdrawals (and related charges), or the step-up death benefit value associated with the 5th contract date anniversary. If the annuitant's age on the contract date was between ages 76 to 80, Travelers Insurance/Travelers Life will pay the beneficiary the greater of contract value or total purchase payments less any withdrawals (and related charges). If the beneficiary was over age 80 on the contract date, Travelers Insurance/Travelers Life will pay the beneficiary contract value. Travelers Insurance/Travelers Life will establish a separate step-up death benefit value on the fifth contract date anniversary and on each subsequent contract date anniversary on or before the date the death is reported to the company. The step-up death benefit value initially equals the contract value on that anniversary. After a step-up death benefit value has been established, Travelers Insurance/Travelers Life will recalculate it each time a purchase payment is made or a withdrawal is taken.

34. If the annuitant is living on the maturity date, Travelers Insurance will pay the owner or his or her designated payee annuity payments beginning on that date. These payments may be in a single lump-sum payment, under any combination of five annuity/income options, or under any other option mutually agreed upon. Should the owner elect to apply his or her contract value to purchase an annuity, Travelers Insurance/Travelers Life, where permitted by law, will add an annuitization credit to the amount applied to purchase the annuity. The credit equals .5% of contract value if the owner annuitizes during contract years 2–5, 1% during contract years 6–10, and 2% after contract year 10.

35. Travelers Insurance/Travelers Life offers four annuity/income options on a fixed or variable basis; the fifth option is offered only on a fixed payment basis. For fixed annuities, an owner may elect to receive a level payment or a payment that will increase by a certain percentage chosen by the owner.

36. Travelers Insurance/Travelers Life will offer two optional annuity benefits. Under the variable annuitization floor benefit, Travelers Insurance/Travelers Life guarantees that, regardless of the performance of the funding options the owner selects, the owner's annuity payments will never be less than a certain percentage of the owner's first variable annuity payment. This percentage will vary depending on market conditions, but will never be less than 50%. As previously discussed, there is a charge for this benefit.

37. Under the liquidity benefit, if an owner selects any annuity option which guarantees payments for a minimum period of time (either a life annuity with a number of payments assured or a fixed annuity), the owner may take a lump sum payment any time after the first contract year. There is a surrender charge of 5% of the amount withdrawn under this option.

Comparison of the UA and TRA Contract Features

38. Applicants submit that the features and benefits of the TRA contract, in almost every respect, are more favorable than under the UA contract.

39. Applicants note that there is a higher threshold for purchase payments under the TRA contract than under the UA contract and that there are fewer funding options available under the UA contract than under the TRA contract. Asset allocation, systematic withdrawal programs, and a Managed Distribution Program are available in both the UA contract and the TRA contract. There is,

however, an additional asset allocation program available under the UA contract, the Tactical Asset Allocation program, that is not offered in the TRA contract.

40. An owner may invest in the Fixed Account under each of the contracts. However, under certain situations, a group contract owner may be assessed a market value adjustment for amounts withdrawn from the Fixed Account under the TRA contract.

41. The UA and TRA contracts provide for similar annuity payment options, but differ greatly on the benefits available during the annuitization period. The UA contract provides for five annuity options and the TRA contract provides for a choice of five annuity options. The UA contract offers three income options; the TRA contract offers one income option. It is the optional features that set the contracts apart and make the point that the focus of the TRA contract is retirement income. The TRA contract provides for several benefits during the annuitization period, including a liquidity option, an annuitization credit, a variable annuitization floor benefit, and an increasing benefit option for fixed annuities. These benefits are not available under the UA contract.

42. The death benefit under the UA contract is, under certain circumstances, potentially not as generous as the standard death benefit under the TRA contract. There is an optional death benefit available for a fee under the TRA contract that provides owners with purchase payment credits and a potentially more generous benefit.

43. Each contract allows the owner to take a withdrawal at any time before the maturity date. However, the free withdrawal amount available under the UA contract is less than what is available under the TRA contract. A systematic withdrawal option and a Managed Distribution Program are offered in both the UA and TRA contracts.

44. Applicants represent that the fees and charges of the basic TRA contract will be no higher than those of the UA contract.

45. Asset-based charges are higher under the UA contract than they are under the TRA contract. Under the UA contract, Travelers Insurance imposes a mortality and expense risk charge as a percentage of average daily net assets of UA Accounts of 1.25% annually. Under the TRA contract, Travelers Insurance/Travelers Life imposes a mortality and expense risk charge as a percentage of average daily net assets of Account Five or Account Six, as relevant, of .80% for the standard death benefit and 1.25% for the enhanced death benefit.

46. Under the UA contract, the owner is assessed a semiannual administrative charge of $15. This charge is not assessed under the TRA contract.

47. Currently, under both the UA contract and TRA contract, no transfer charge is assessed. However, under each contract, the company reserves the right to assess the charge in the future.

48. The contingent deferred sales charge is higher under the UA contract than it is under the TRA contract. Under the UA contract, a contingent deferred sales charge of 5.00% is assessed if a purchase payment is withdrawn within 5 years after that purchase payment is made. The charge does not decline. Similarly, under the TRA contract a withdrawal charge is assessed if a purchase payment (including applicable credits) is withdrawn within 5 years after that payment is made. However, unlike with the UA contract, under the TRA contract the withdrawal charge declines each year so that the amount of the charge is 0% if the purchase payment is withdrawn 5 or more years after the purchase payment is made.

Proposed Exchange

49. Applicants propose to offer eligible owners of UA contracts the opportunity to exchange their UA contracts for TRA contracts. To be eligible to participate in the exchange offer:

- The UA owner must have purchased his or her contract in connection with a retirement plan that met the requirements under section 403(b) or 457 under the Code;
- The plan under which the UA owner purchased his or her contract no longer uses The Travelers Insurance Company as its primary insurance carrier for the employer's section 403(b) or 457 plan or the UA owner no longer actively contributes to his or her contract;
- The UA owner meets the minimum eligibility requirements to purchase the TRA contract (*i.e.*, the owner must be at least 40 years of age and make an initial purchase payment of at least $20,000); and
- The UA owner's contract must be at least 5 years old.

Applicants submit that the program will be beneficial to owners who, because of the terms of their employer's 403(b) or 457 plan, may no longer be able to contribute to their UA contract because it provides such owners the opportunity to invest in the lower cost TRA contract that offers them innovative death benefits options and more annuitization options (including liquidity and guaranteed floor provisions).

50. After an initial notification of the exchange offer in quarterly reports or other communications to eligible UA contract owners and contacts made by Travelers Distribution's registered representatives, the exchange offer will be made by providing eligible owners of the UA contracts who express an interest in learning the details of the offer a prospectus for the TRA contract, accompanied by a letter explaining the offer, a piece of sales literature that compares the UA contract to the TRA contract, and an internal exchange form. The offering letter will advise owners of a UA contract that the exchange offer is specifically designed for those owners who intend to continue to hold their contracts as long-term investment vehicles. The letter will state that the offer is not intended for all owners, and that it is not appropriate for any owner who anticipates surrendering all or a significant part (*i.e.*, more than 20% on an annual basis) of his or her contract before the end of five years. Further, the letter will encourage owners to carefully evaluate their personal financial situations when deciding whether to accept or reject the exchange offer.

51. Applicants represent that the offering letter also will explain how an owner of a UA contract contemplating an exchange may avoid the applicable withdrawal charge on the TRA contract if no more than the ''free withdrawal amount'' is surrendered and any subsequent deposits are held until the expiration of the withdrawal period. In this regard, the offering letter will state in plain English that if the TRA contract is surrendered during the withdrawal charge period:

- Any purchase payment credit that the owner may receive if he or she elects the optional death benefit, may be more than offset by the withdrawal charge; and
- An owner may be worse off than if he or she had rejected the exchange offer.

52. An internal exchange application form, which will accompany the offering letter, will include an owner acknowledgement section with check-off boxes setting forth specific questions designed, among other things, to determine a contract owner's suitability for the exchange offer. In particular, the form will seek affirmative confirmation that an owner does not anticipate a need to withdraw more than 20% per year (plus earnings) from the TRA contract during the withdrawal period. Other questions on the form will seek owner acknowledgment that the exchange offer is suitable only for an owner if he or she

expects to hold the TRA contract through annuitization, and that the owner may be better off rejecting the exchange offer if he or she plans to surrender the TRA contract during the withdrawal period. All boxes on the form must be checked off with affirmative responses before Travelers Insurance/Travelers Life will process the exchange. After making a suitability determination, each broker-dealer will be required to forward completed forms to Travelers Insurance/Travelers Life for processing. In the event either company receives an incomplete form (*i.e.*, a form with one or more acknowledgment boxes not checked off), Travelers Insurance/Travelers Life will not process the exchange, treating the transaction as ''not in good order.'' Travelers Insurance/Travelers Life intends to contact any broker-dealer who submits a form not in good order, however, in no event will Travelers Insurance/Travelers Life process exchange transactions based on incomplete forms.

53. Travelers Insurance/Travelers Life will apply the cash value of the UA contract, together with any applicable purchase payment credit, and any additional purchase payments submitted with an internal exchange application form for the TRA contract to the TRA contract on the exchange date. Travelers Insurance will not deduct a contingent deferred sales charge upon the surrender of a UA contract in connection with the exchange offer.

54. After expiration of the TRA contract's right to return period, surrenders and withdrawals will be governed by the terms of the TRA contract for purposes of calculating any withdrawal charge. This means, in part, that Travelers Insurance/Travelers Life will not recapture any purchase payment credit applied to the contract value of the TRA contract, unless the owner were to cancel the contract during the right to return period.

55. The exchange date will be the issue date of the TRA contract for purposes of determining contract years and anniversaries after the exchange date.

56. To accept the exchange offer, a UA contract owner must complete an internal exchange application form. Contract values under the TRA contract will be allocated according to owner instructions. Travelers Insurance/Travelers Life will assume purchase payments submitted with the internal exchange application form to be payments under the TRA contract as of the date of issue of the TRA contract.

57. UA owners who accept the exchange offer will not be subject to any adverse tax consequences. The exchanges will constitute tax-free exchanges under section 1035 of the Code.

58. Travelers Insurance/Travelers Life will compensate broker-dealers in connection with the proposed exchange offer. These broker-dealers will receive the same compensation they would have received had there been a new sale of a TRA contract without the exchange program.

Applicants' Legal Analysis

1. Section 11 of the 1940 Act makes it unlawful for any registered open-end company or any principal underwriter for such a company to make or cause to be made an offer to the holder of a security of such company or of any other open-end investment company to exchange his or her security for a security in the same or another such company on any basis other than the relative net asset values of the respective securities to be exchanged, unless the terms of the offer have first been submitted to and approved by the Commission or are in accordance with Commission rules and regulations adopted under section 11. Section 11(c) of the 1940 Act, in pertinent part, makes section 11(a) applicable to an offer of exchange of the securities of a registered unit investment trust for the securities of any other investment company, irrespective of the basis of the exchange. Accounts GIS, MM, QB, TAS, TGIS, and TSB are registered with the SEC as open-end diversified management investment companies, and Fund U and Accounts Five and Six are registered with the SEC as unit investment trusts. Accordingly, the proposed exchange offer is subject to section 11(a) under the 1940 Act and can only be made after the Commission has approved the terms of the offer under section 11(a). Applicants submit that the terms of the proposed exchange offer do not present the abuses section 11 was designed to prevent, and are consistent with public policy and Commission precedent.

2. As noted by the Commission when proposing rule 11a–3 under the 1940 Act, the purpose of section 11 of the Act is to prevent ''switching.'' ''Switching'' is the practice of inducing security holders of one investment company to exchange their securities for those of a different investment company solely for the purpose of exacting additional selling charges. This practice was found by Congress to be widespread in the 1930's before the adoption of the 1940 Act.

3. Section 11(c) of the 1940 Act requires Commission approval (by order or rule) of any exchange, regardless of its basis, involving securities issued by a unit investment trust, because investors in unit investment trusts were found by Congress to be particularly vulnerable to switching operations. Applicants note that the legislative history of section 11 makes clear that the potential for harm to investors perceived in switching was its use to extract additional sales charges from investors.

4. Applicants represent that the terms of the proposed exchange offer do not present the abuses (*i.e.*, the additional sales charges that result from abusive switching practices) against which section 11 was designed to prevent. Applicants submit that the purpose of their exchange offer is not to earn additional sales commissions; rather, the purpose of the offer is to give investors, many of whom because of the terms of their employer's 403(b) and 457 plans may no longer be able to contribute towards their retirement, an opportunity to invest in a lower cost contract that has innovative death benefit and annuitization features. In stark contrast with the 9–10% front-end commission deducted in the ''switching'' exchanges that led to adoption of section 11, each UA owner accepting the exchange offer may be able to receive a 2% purchase payment credit added to each purchase payment should the owner elect the optional death benefit. The effect of the credit is to add to cash value at the time of the exchange. This credit provides a significant benefit to the owner because neither Travelers Insurance nor Travelers Life will recapture the amount of that credit should the owner make a withdrawal from or surrender his or her contract after the expiration of the TRA contract's right to return period. Further, the TRA contract offers the owner the opportunity to receive additional economic benefits upon annuitization. At that time, each company will add an annuitization credit to the value of an owner's contract. In addition, no sales charges will be imposed on amounts surrendered from a UA contract and applied to a TRA contract, and no sales charges ever will be paid on amounts rolled over in the exchange unless the TRA contract is surrendered before the expiration of the TRA contract's initial withdrawal charge period.

5. Rule 11a–2 permits an offer to exchange one variable annuity contract which has a contingent deferred sales load for another variable annuity contract which also has a contingent deferred sales load of the same or of an affiliated insurer without obtaining Commission approval, as long as (i) no

surrender charge is deducted at the time of the exchange, and (ii) in computing the surrender charge for the new contract, the insurer gives credit for the period during which the contract owner held the old contract (the ''tacking requirement''). Amounts exchanged from a UA contract and deposited into the TRA contract are precluded from relying on rule 11a–2 because, in computing the withdrawal charge on amounts surrendered or withdrawn from a UA contract and deposited into the TRA contract, Travelers Insurance/Travelers Life will not give credit for the period during which the owner held the amount in the UA contract.[7] Applicants state that it is not economically feasible for Travelers Insurance/Travelers Life to ''tack'' for purposes of assessing the withdrawal charge under the TRA contract.

6. Applicants submit that tacking is not a requirement of section 11. Instead, it is a creation of rule 11a–2 designed to approve the terms of exchange offers ''sight unseen.'' Congress adopted section 11 well before the first contingent deferred sales load.

7. Applicants state that tacking focuses on the closest thing to multiple deductions of sales charges that is possible in the contingent deferred sales charges context—*i.e.*, whether there are multiple sales loads upon surrender and redemption. Applicants note that if that safeguard, as well as other safeguards provided by rule 11a–2 are present, the Commission has determined that there is no need for it or its staff to evaluate the offer. Applicants submit that tacking should be viewed as a useful way to avoid the need to scrutinize the terms of an offer of exchange to make sure that there is no abuse; tacking should not be relevant in situations where the SEC will fully scrutinize the terms of an exchange offer. The absence of tacking does not mean that the proposed exchange offer is without clear benefits to investors. Applicants believe that the proposed exchange offer presents less potential for the type of abuses that led to the adoption of section 11 than in connection with exchanges that would be permitted under rule 11a–2.

8. Applicants submit that they are offering a beneficial investment opportunity to certain UA owners. The proposed exchange offer is offered to those owners many of whom, because of the terms of their employer's 403(b) or 457 plans, may no longer be able to contribute to their current UA contracts, or to those UA owners who no longer actively contribute to his or her contract. Applicants represent that the proposed exchange offers such individuals the opportunity to once again contribute towards their retirement under the lower cost TRA contract. Far from being a way to extract additional charges from investors, as contemplated by the prohibitions of section 11, Applicants submit that the proposed exchange offer would assure, in most instances, an immediate and enduring economic benefit to investors. The 2% purchase payment credit would be applied immediately should the owner elect the optional death benefit, and the fact that asset-based and other charges would remain the same or be decreased by the exchange (asset-based charges only would be decreased if an owner were to elect the standard death benefit) would ensure that the benefit would endure. Further, Applicants note that the TRA contract offers several features which are not available under the UA contract which the UA contract owner may enjoy. These include: the optional death benefit with purchase payment credits, a greater free withdrawal amount (20% of contract value) without the imposition of the withdrawal charge, a declining withdrawal charge, an annuitization credit, a liquidity option during the annuitization period, and the ability to receive variable annuity payments in at least a certain minimum amount. Applicants believe that, in almost every respect, the proposed exchange would be beneficial to the offerees. Applicants represent that the only significant downside that may occur as a result of the exchange is if the owner, instead of holding his or her investment for the long-term, as variable annuity contracts are designed to be, surrenders or withdraws certain amounts from his or her TRA contract before the end of the withdrawal period.

9. Applicants state that the exchange offer will be available to all owners who meet the applicable eligibility and suitability standards on a voluntary basis. The decision to participate in the exchange offer will be made by each owner, after he or she has been given the opportunity to evaluate the proposed exchange offer. Applicants note that the offering letter from Travelers Insurance will give a UA contract owner a full explanation of both the advantages and disadvantages of the exchange.

10. Applicants submit that the proposed exchange offer is consistent with the purposes of the National Securities Improvement Act of 1996 (''NSMIA''). The purpose of NSIMA was to promote competition and capital formation as well as to ''eliminate[ ] burdens and enhance[ ] innovation and efficiency for investment companies.''[8] These concepts are codified in section 2 of the 1940 Act. Applicants submit that the proposed exchange offer will promote competition because it will allow Travelers Insurance to retain business it otherwise might have lost because it is no longer the primary insurance carrier for certain 403(b) and 457 plans.

11. Applicants submit that there is ample precedent to support the various features of their exchange offer, including precedent relating to the compensation of salesmen, the granting of an order where the exchange might be disadvantageous to certain owners, and relief from rule 11a–2's tacking requirement.

Conditions

If the requested order is granted, Applicants consent to the following conditions which are intended to support the understanding that the exchange offers are being made to owners who expect to persist:

1. The offering letter will contain concise plain English statements that: (a) The exchange offer is suitable only for UA owners who expect to hold their contracts as long-term investments; and (b) if the TRA contract is surrendered during the withdrawal charge period:

- Any purchase payment credit that the owner may receive if he or she elects the optional death benefit, may be more than offset by the withdrawal charge; and
- An owner may be worse off than if he or she had rejected the exchange offer.

2. Travelers Insurance/Travelers Life will provide a means of confirming that an owner choosing to participate in the exchange offer was told of the statements required in the offering letter (stated in condition no. 1). Travelers Insurance will send the offering letter directly to eligible UA owners. An owner choosing to participate in the program will then complete and sign an internal exchange form, which will prominently restate in concise, plain English the statements required in condition no. 1 and return it to Travelers Insurance. If the internal exchange form is more than two pages in length, Travelers Insurance will use a separate document to obtain owner acknowledgment of the statements required by condition no. 1.

[7] Applicants not that the proposed exchange may not be considered to be at relative net asset value because of the addition of the purchase payment credit to amounts exchanged into a TRA contract should the owner elect the optional death benefit.

[8] H.R. Conf. Rep. No. 104–864, at 40 (Sept. 28, 1996).

3. Travelers Insurance and Travelers Life, as appropriate, will maintain the following separately identifiable records in an easily accessible place, for the time periods specified below in this condition no. 3, for review by the Commission upon request: (a) Records showing the level of exchange activity and how it relates to total number of owners eligible for the exchange offer (quarterly as a percentage of the number eligible); (b) copies of any form of offering letter and other written materials and scripts for presentations by representatives regarding the exchange offer (if Travelers Insurance prepared or approved the materials), including the dates(s) used; (c) records showing information about each exchange transaction that occurs, including the name of the owner; the UA contract and TRA contract number(s); contingent deferred sales charge waived at surrender of the UA contract; purchase payment credit applied, if any; registered representative's name, CRD number, firm affiliation, branch office address and telephone number, and the name of the registered representative's broker-dealer; commission paid; internal exchange form (and separate document, if any, used to obtain owner acknowledgment of the statements required in condition no. 1) showing the name, date of birth, address and telephone number of the owner, and date the internal exchange form (or separate document) was signed; amount of cash value exchanged; and persistency information relating to the TRA contract (date surrendered and withdrawal charge paid); and (d) logs showing any owner complaints about the exchange offer, state insurance department inquiries about the exchange offer, or litigation, arbitration or other proceedings regarding any exchange. The following information will be included on the logs: date of complaint or commencement of the proceeding; nature of the complaint or proceeding; and persons named or involved in the complaint or proceeding.

4. Records specified in condition no. 3(a) and (d) will be retained for six years from creation of record. Records specified in condition no. 3(b) will be retained for six years after the date of last use, and records specified in condition no. 3(c) will be retained for two years from the end of the initial withdrawal period of the TRA contract.

5. The offering letter will disclose in concise plain English each aspect of the TRA contract that is less favorable than the UA contract.

Conclusion

For the reasons stated above, Applicants believe that the requested exemption in accordance with the standards of section 11(a), are appropriate in the public interest and consistent with the protection of investors and the purposes fairly intended by the policy and provisions of the 1940 Act.

For the Commission, by the Division of Investment Management, pursuant to delegated authority.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 03–1810 Filed 1–27–03; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–47231; File No. SR–OPRA–2002–01]

Options Price Reporting Authority; Order Granting Permanent Approval to an Amendment To Establish a Best Bid and Offer Market Data Service

January 22, 2003.

On February 26, 2002, the Options Price Reporting Authority (''OPRA'') submitted to the Securities and Exchange Commission (''Commission''), pursuant to section 11A of the Securities Exchange Act of 1934 (''Act'')[1] and rule 11Aa3–2 thereunder,[2] an amendment to the Plan for Reporting of Consolidated Options Last Sale Reports and Quotation Information (''OPRA Plan'' or ''Plan'').[3] The proposed amendment would add to the Plan terms governing the provision by OPRA of a best bid and offer (''BBO'') for each of the options series included in OPRA's market data service, and governing the use of the BBO by vendors.

Notice of the proposal was published in the **Federal Register** on March 15, 2002.[4] The Commission received two comment letters on the proposed OPRA Plan amendment.[5] On May 30, 2002, OPRA submitted Amendment No. 1 to the proposal.[6] On June 13, 2002, OPRA submitted a letter in response to the comments.[7] On October 4, 2002, OPRA submitted Amendment No. 2 to the proposal.[8] On December 13, 2002, the Commission approved the proposal as modified by Amendment Nos. 1 and 2 on a temporary basis for 120 days, and solicited comment on Amendment Nos. 1 and 2.[9] The Commission received no comments on Amendment Nos. 1 and 2. This order approves the OPRA Plan amendment, as modified by Amendment Nos. 1 and 2, on a permanent basis.

Under the proposed Plan amendment, OPRA proposes to add a consolidated BBO service that would disseminate the best bid and offer for each options series, and OPRA would prioritize the BBO on the basis of price, size, and time. In addition, OPRA's BBO service could reflect an approximation of the quotation size associated with the best bid or offer actually available.

Under the proposal, OPRA vendors would have the option to disseminate to customers the consolidated BBO together with last sale reports for any series of options in place of OPRA's full market data service. In addition to the BBO service, OPRA would be obligated to continue to offer to vendors its full market data service, which includes the disseminated best bid and offer from each of OPRA's participant exchanges. The proposed amendment also would permit OPRA to contract with vendors separately for: (i) The last sale reports and the BBO; or (ii) for the last sale reports, the BBO, and quotation information from each market. OPRA also could contract separately with vendors for the full market data service that it currently offers.

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[1] 15 U.S.C. 78k–1.

[2] 17 CFR 240.11Aa3–2.

[3] OPRA is a National Market System Plan approved by the Commission pursuant to section 11A of the Act and rule 11Aa3–2 thereunder. *See* Securities Exchange Act Release No. 17638 (March 18, 1981).

The OPRA Plan provides for the collection and dissemination of last sale and quotation information on options that are traded on the participant exchanges. The five participants to the OPRA Plan that operate an options market are the American Stock Exchange LLC, the Chicago Board Options Exchange, Inc. (''CBOE''), the International Securities Exchange, Inc., the Pacific Exchange, Inc., and the Philadelphia Stock Exchange, Inc. The New York Stock Exchange, Inc. is a signatory to the OPRA Plan, but sold its options business to the CBOE in 1997. *See* Securities Exchange Act Release No. 38542 (April 23, 1997).

[4] *See* Securities Exchange Act Release No. 45532 (March 11, 2002), 67 FR 11727.

[5] *See* letters from Devin Wenig, President, Investment Banking and Brokerage, Reuters America Inc., dated April 19, 2002, and George W. Mann, Jr., Executive Vice President and General Counsel, Boston Stock Exchange Inc., dated May 1, 2002, to Jonathan G. Katz, Secretary, Commission.

[6] *See* letter from Joseph P. Corrigan, Executive Director, OPRA, to John Roeser, Special Counsel, Division of Market Regulation (''Division''), Commission, dated May 29, 2002 (''Amendment No. 1'').

[7] *See* letter from Joseph P. Corrigan, Executive Director, OPRA, to John Roeser, Special Counsel, Division, Commission, dated June 12, 2002.

[8] *See* letter from Joseph P. Corrigan, Executive Director, OPRA, to John Roeser, Special Counsel, Division, Commission, dated October 2, 2002 (''Amendment No. 2'').

[9] *See* Securities Exchange Act Release No. 46992 (December 13, 2002), 67 FR 78031 (December 20, 2002).

After careful review, the Commission finds that the proposed OPRA Plan amendment, as amended by Amendment Nos. 1 and 2, is consistent with the requirements of the Act and the rules and regulations thereunder.[10] Specifically, the Commission believes that the proposed OPRA Plan amendment, as amended, which would permit OPRA to provide a best bid and offer market data service to vendors, is consistent with section 11A of the Act [11] and rule 11Aa3–2 thereunder [12] in that it is appropriate in the public interest, for the protection of investors and the maintenance of fair and orderly markets, to remove impediments to, and perfect the mechanisms of, a national market system or otherwise in furtherance of the purposes of the Act.

Specifically, the Commission believes that OPRA's proposal to permit vendors to disseminate last sale information and a BBO is consistent with section 11A of the Act [13] because the combination of the consolidated BBO and the last sale reports would include the minimum essential pricing information market participants need to make informed investment decisions. Furthermore, the Commission notes that all markets would have an equal opportunity to be represented in the BBO. OPRA's proposed BBO service should make it easier for vendors to disseminate this minimum essential market information as an alternative to the full quotation information or in addition to such information.

Finally, the Commission notes that it is simultaneously approving OPRA's proposal to change its vendor agreement, which will affect the manner in which vendors may disseminate information to end users.[14] Specifically, under OPRA's vendor agreement proposal, vendors could choose to disseminate only the BBO and last sale information and exclude from the BBO the quotation size, or the market identifier associated with a BBO, or both, so long as in excluding this information the vendor did not discriminate on the basis of the market in which quotations are entered.

It is therefore ordered, pursuant to section 11A of the Act,[15] and rule 11Aa3–2 thereunder,[16] that the proposed OPRA Plan amendment, as modified by Amendment Nos. 1 and 2 (SR–OPRA–2002–01) be, and it hereby is, approved on a permanent basis.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[17]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 03–1883 Filed 1–27–03; 8:45 am]

BILLING CODE 8010–01–U

[10] In approving this proposed OPRA Plan amendment, the Commission has considered its impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[11] 15 U.S.C. 78k–1.

[12] 17 CFR 240.11Aa3–2.

[13] 15 U.S.C. 78k–1.

[14] See Securities Exchange Act Release No. 47230 (January 22, 2003) (order approving File No. SR–OPRA–2002–03).

[15] 15 U.S.C. 78k–1.

[16] 17 CFR 240.11Aa3–2.

[17] 17 CFR 200.30–3(a)(29).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–47230; File No. SR–OPRA–2002–03]

Options Price Reporting Authority; Order Approving an Amendment to the Options Price Reporting Authority Plan To Revise the Required Form of Vendor Agreement

January 22, 2003.

I. Introduction

On July 12, 2002, the Options Price Reporting Authority (''OPRA'') submitted to the Securities and Exchange Commission (''SEC'' or ''Commission''), pursuant to section 11A of the Securities Exchange Act of 1934 (''Act'')[1] and rule 11Aa3–2 thereunder,[2] an amendment to the Plan for Reporting of Consolidated Options Last Sale Reports and Quotation Information (''OPRA Plan'' or ''Plan'').[3] The amendment would revise the form of Vendor Agreement that is required to be entered into between OPRA and vendors of options information under section VII(b) of the OPRA Plan. Notice of the proposal was published in the **Federal Register** on November 21, 2002.[4] The Commission received no comment letters on the proposed OPRA Plan amendment. This order approves the proposal.

OPRA's Vendor Agreement governs the terms and conditions under which vendors redistribute options market data to subscribers and other end users of the information. The proposed revisions would update the Vendor Agreement and consolidate a series of riders to the Vendor Agreement. In addition, the revised Vendor Agreement would consolidate several different forms of agreements between vendors and their customers into a single standard form ''Subscriber Agreement,'' without making any significant substantive changes to the current forms.

The revised Vendor Agreement would also include new provisions to govern the redistribution by vendors of OPRA's new BBO (best bid and offer) Service.[5] In this regard, the revised Vendor Agreement would permit a vendor to satisfy its obligation to include consolidated options market data in its market information service if, at a minimum, the service would include options last sale information and the consolidated BBO provided by OPRA. This would permit a vendor to include additional unconsolidated information in its service so long as this required minimum consolidated information is included. Further, the revised Vendor Agreement would permit a vendor to exclude from its BBO service either the quote size or the market identifier associated with a BBO or both, so long as in excluding information the vendor would not discriminate on the basis of the market in which quotations are entered. In addition, if a vendor were to exclude the market identifier associated with the BBO from a dynamically updated service, it would be required to make that information available to recipients of the dynamically updated service through an inquiry-only service provided without additional cost. Finally, because OPRA's BBO Service provides for the inclusion of an approximation of the size associated with the BBO rather than the actual size, the revised Vendor Agreement would require any vendor that includes size in its BBO service to disclose to its customers that the included size is an approximation of the actual size, and that the actual size is available on OPRA's full quotation service.

After careful review, the Commission finds that the proposed OPRA Plan

[1] 15 U.S.C. 78k–1.

[2] 17 CFR 240.11Aa3–2.

[3] OPRA is a National Market System Plan approved by the Commission pursuant to section 11A of the Act and rule 11Aa3–2 thereunder. *See* Securities Exchange Act Release No. 17638 (March 18, 1981).

The OPRA Plan provides for the collection and dissemination of last sale and quotation information on options that are traded on the participant exchanges. The five participants to the OPRA Plan that operate an options market are the American Stock Exchange LLC, the Chicago Board Options Exchange, Inc. (''CBOE''), the International Securities Exchange, Inc., the Pacific Exchange, Inc., and the Philadelphia Stock Exchange, Inc. The New York Stock Exchange, Inc. is a signatory to the OPRA Plan, but sold its options business to the CBOE in 1997. *See* Securities Exchange Act Release No. 38542 (April 23, 1997), 62 FR 23521 (April 30, 1997).

[4] *See* Securities Exchange Act Release No. 46839 (November 14, 2002), 67 FR 70269.

[5] *See* Securities Exchange Act Release No. 47231 (January 22, 2003) (File No. SR–OPRA–2002–01) (order granting permanent approval). *See also* Securities Exchange Act Release No. 46992 (December 13, 2002), 67 FR 78031 (December 20, 2002).

amendment is consistent with the requirements of the Act and the rules and regulations thereunder.[6] The Commission believes that the proposed OPRA Plan amendment is consistent with section 11A of the Act[7] and rule 11Aa3–2 thereunder[8] in that it is appropriate in the public interest, for the protection of investors and the maintenance of fair and orderly markets, to remove impediments to, and perfect the mechanisms of, a national market system.

Specifically, the Commission notes that the Vendor Agreement governs the terms and conditions under which vendors are permitted to redistribute options market data to subscribers and other end users of the information, and includes new provisions to implement various aspects of OPRA's best bid and offer (''BBO'') Service, which the Commission recently approved.[9] In particular, the revised Vendor Agreement would allow a vendor, subject to certain limitations, to exclude information regarding quotation size and market identification from its redistribution of OPRA's BBO Service. The Commission notes that if a vendor excludes either the quotation size or market identifier from its service, or both, it must not discriminate on the basis of the market in which quotations were entered. In addition, if a vendor excludes the market identifier associated with the BBO from a dynamically updated service, it would be required to make that information available to recipients of the dynamically updated service through an inquiry-only service provided without additional cost. The Commission believes that this provision of the proposal is consistent with the purposes of section 11A of the Act because vendors would be required to make available to their subscribers the information investors need to make informed investment decisions.

It is therefore ordered, pursuant to section 11A of the Act,[10] and rule 11Aa3–2 thereunder,[11] that the proposed OPRA Plan amendment, (SR–OPRA–2002–03) is approved.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[12]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 03–1880 Filed 1–27–03; 8:45 am]

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[6] In approving this proposed OPRA Plan amendment, the Commission has considered its impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[7] 15 U.S.C. 78k–1.

[8] 17 CFR 240.11Aa3–2.

[9] *See supra* note .

[10] 15 U.S.C. 78k–1.

[11] 17 CFR 240.11Aa3–2.

[12] 17 CFR 200.30–3(29).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–47220; File No. SR–ISE–2002–24]

Self-Regulatory Organizations; International Securities Exchange, Inc.; Order Approving Proposed Rule Change Relating to Quotation Size and Notice of Filing and Order Granting Accelerated Approval of an Amendment to the Proposal

January 21, 2003.

On October 11, 2002, the International Securities Exchange, Inc. (''ISE'') filed with the Securities and Exchange Commission (''Commission''), pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and rule 19b–4 thereunder,[2] a proposed rule change that would require ISE quotations to be firm for their published sizes for all orders entered by ISE members, regardless of whether such orders are for the accounts of customers or broker-dealers. The proposal would allow ISE to eliminate its current distinction between the sizes of quotations for all orders, except for trades involving the interaction of ISE market maker quotations. On November 1, 2002, the Exchange's rule proposal was published for comment in the **Federal Register**.[3] No comments letters were received on the proposal. On November 21, 2002, the ISE submitted a letter to withdraw proposed paragraph (c) of ISE rule 805, which would have limited market makers from sending more than one order every fifteen seconds in an option on the same underlying security.[4] This order approves the proposed rule change, as amended by the ISE letter, publishes notice of the ISE letter, and grants accelerated approval to ISE's withdrawal of proposed ISE rule 805(c).

The proposal would require that all ISE quotations be firm for all incoming orders for their full disseminated size, except for matching quotations of ISE market makers. Specifically, each ISE Primary Market Maker and Competitive Market Maker would enter a quotation with a single size, available in full for all incoming orders, whether from customers, broker-dealers, ISE market makers or market makers on other exchanges, except for ISE market maker quotations. In the case of ISE market maker quotations, the ISE proposes to establish by rule that ISE market makers must be firm for at least one contract for quotations of other ISE market makers. To implement this proposal, the ISE would require a limited exemption from rule 11Ac1–1 (the ''Quote rule'')[5] to permit the Exchange to establish by rule a quotation size for which a responsible broker or dealer is obligated to trade with matching ISE market maker quotations, provided that such responsible broker or dealer is firm to all other customer and broker-dealer orders for the amount of its quotation size communicated to the ISE.[6]

Finally, the ISE proposes two technical changes to update its rules. First, the Exchange proposes to delete language from ISE rule 804 regarding the ''enhanced size pilot'' that expired on October 31, 2002. Second, the Exchange proposes to delete language from ISE rule 805 regarding limited exemptive authority that expired a year after the Exchange commenced trading.

Interested persons are invited to submit written data, views and arguments concerning the ISE Letter, including whether it is consistent with the Act. Persons making written submissions should file six copies

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 46723 (October 25, 2002), 67 FR 66693.

[4] *See* letter from Michael Simon, Senior Vice President and General Counsel, ISE, to Nancy Sanow, Assistant Director, Division of Market Regulation (''Division''), Commission, dated November 20, 2002 (''ISE letter'').

[5] 17 CFR 240.11Ac1–1

[6] In connection with this proposal, the ISE submitted a separate letter requesting an exemption from certain requirements of the Quote rule. *See* letter from Michael Simon, Senior Vice President and General Counsel, ISE, to Annette Nazareth, Director, Division, Commission, dated October 10, 2002. Concurrent with approval of this proposal, the Commission granted ISE's request for a limited exemption from the Quote rule. Specifically, the Commission determined to grant responsible brokers or dealers on the ISE an exemption from their obligations under rule 11Ac1–1(c)(1) to communicate to the ISE their quotation sizes applicable to the quotations of ISE market makers, provided that: (1) Such responsible brokers or dealers promptly communicate to the ISE the quotation sizes for which they are obligated to execute at their published quotation any order, other than a quotation by an ISE market maker; (ii) such responsible brokers or dealers comply with their obligations under paragraph (c)(2) of rule 11Ac1–1 by trading with quotations by other ISE market makers, in an amount up to the size established by the ISE; and (iii) the ISE and its responsible broker or dealers do not rely on paragraphs (d)1) and (2) of the Quote rule. *See* letter from Robert Colby, Deputy Director, Division, Commission, to Michael Simon, Senior Vice President and General Counsel, ISE, dated January 21, 2003.

thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609. 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 in the Commission's Public Reference Room. Copies of such filing will also be available for inspection and copying at the principal office of the ISE. All submissions should refer to the ISE letter of File No. SR–ISE–2002–24 and should be submitted by February 18, 2003.

After careful review, the Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange [7] and, in particular, the requirements of section 6 of the Act.[8] Specifically, the Commission finds that the proposal to require ISE market makers to be firm for up to their disseminated amount to all orders, other than matching ISE market maker quotations, is consistent with section 6(b)(5) of the Act,[9] in that by ensuring that a larger number of orders may be executed at a better price, the proposed rule change has been designed to remove impediments to and to perfect the mechanism of a free and open market and a national market system, while also protecting investors and the public interest.

The original rule proposal, including the proposal to add ISE rule 805(c), which the ISE subsequently withdrew by letter, was noticed for public comment on November 1, 2002. No comments were received on any aspect of the proposal. Because the ISE letter merely withdraws one provision of the proposal, which was previously published for comment, and because by withdrawing the one provision to add ISE rule 805(c), no other aspect of the proposal is affected, the Commission believes that approving this change to the proposal on an accelerated basis is appropriate. Accordingly, pursuant to section 19(b)(2) of the Act,[10] the Commission finds good cause to approve the change to the proposal set forth in the ISE Letter prior to the thirtieth day after notice of the ISE letter is published in the **Federal Register**.

It is therefore ordered, pursuant to section 19(b)(2) of the Act,[11] that the proposed rule change (File No. SR–ISE–2002–24) is hereby approved, as amended by the ISE letter, which is hereby approved on an accelerated basis.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[12]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 03–1882 Filed 1–27–03; 8:45 am]

BILLING CODE 8010–01–P

[7] The Commission has considered the proposed rules' impact on efficiency, competition and capital formation. 15 U.S.C. 78c(f).

[8] 15 U.S.C. 78f.

[9] 15 U.S.C. 78f(b)(5).

[10] 15 U.S.C. 78s(b)(2).

[11] 15 U.S.C. 78s(b)(2).

[12] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–47221; File No. SR–NYSE–2002–11]

Self-Regulatory Organizations; Notice of Filing of Proposed Rule Change and Amendment No. 1 Thereto by the New York Stock Exchange, Inc. To Establish a Six-Month Pilot Program Permitting a Floor Broker To Use an Exchange Authorized and Issued Portable Telephone on the Exchange Floor

January 21, 2003.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and rule 19b–4 thereunder,[2] notice is hereby given that on February 28, 2002, the New York Stock Exchange, Inc. (''NYSE'' or ''Exchange'') 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 Exchange. On December 30, 2002, the Exchange filed an amendment to the proposed rule change.[3] The Commission is publishing this notice to solicit comments on the proposed rule change, as amended, from interested persons.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* letter from Darla C. Stuckey, Corporate Secretary, NYSE, to Nancy J. Sanow, Assistant Director, Division of Market Regulation, Commission, dated December 30, 2002 (''Amendment No. 1''). Amendment No. 1 replaces the filing in its entirety and provides, in the proposed rule text and the purpose section of the filing, clarification and further details on the use of Exchange authorized and issued portable telephones on the Exchance floor.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend NYSE rule 36 (Communication Between Exchange and Members' Offices) to allow a Floor broker's use of an Exchange authorized and provided portable telephone on the Exchange Floor upon approval by the Exchange, by deleting the current prohibition against such use. Below is the text of the proposed rule change, as amended. Proposed new language is *italicized;* proposed deletions are in brackets.

Rule 36 Communications Between Exchange and Members' Offices

No member or member organization shall establish or maintain any telephonic or electronic communication between the Floor and any other location without the approval of the Exchange. The Exchange may to the extent not inconsistent with the Securities Exchange Act of 1934, as amended, deny, limit or revoke such approval whenever it determines, in accordance with the procedures set forth in Rule 475, that such communication is inconsistent with the public interest, the protection of investors or just and equitable principles of trade.

Supplementary Material

.10 Installation of telephone lines to Exchange.—The Telephone Company will not recognize any order for the installation or disconnection of a telephone line between the Floor and any other location, except such orders as are issued by the Exchange directly to the Telephone Company.

Requests for telephone lines should be sent to Market Operations Division. Members or member organizations who desire such installations or disconnections should present their requests sufficiently in advance of the desired effective date to avoid any inconvenience resulting from insufficient notice to the Telephone Company.

.20 With the approval of the Exchange, a member or member organization *other than a specialist or specialist member organization* may maintain a telephone line *or use an Exchange authorized and provided portable telephone* which permits a non-member off the Floor to communicate with a member or member organization on the Floor. *However, use of an Exchange authorized and provided portable telephone is not permitted for orders in Investment Company Units (as defined in Section*

703.16 of the Listed Company Manual). In addition, any Floor broker receiving orders from the public over portable phones must be properly qualified under Exchange rules to conduct such business (See, for e.g., Rules 342 and 345.) The use of a portable telephone on the Floor other than one authorized and issued by the Exchange is prohibited.

In the case of members or member organizations acting solely in connection with transactions in ''baskets'' (as Rule 800 (Basket Trading: Applicability and Definitions) defines that term), the Exchange may approve the maintenance of such telephone lines at the basket trading location. In all other instances, the Exchange will approve the maintenance of such telephone lines only at the booth location of a member or member organization. [The Exchange will not approve the use of a portable telephone on the Floor].

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 Exchange included statements concerning the purpose of, and basis for, the proposed rule change, as amended, and discussed any comments it received on the proposed rule change, as amended. The text of these statements may be examined at the places specified in item IV below and is set forth in sections A, B, and C below.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

NYSE rule 36 governs the establishment of telephone or electronic communications between the Exchange's Trading Floor and any other location. Rule 36.20 prohibits the use of portable telephone communications between the Trading Floor and any off-Floor location. The only way that voice communication can be conducted today by Floor brokers between the Trading Floor and an off-Floor location is by means of a telephone located at a broker's booth. Communications often involve a customer calling a broker at the booth for ''market look'' information. A broker may not use a portable phone currently in a trading Crowd at the point of sale to speak with a person located off the Floor.

The Exchange is proposing to amend NYSE rule 36 to permit a Floor broker to use an Exchange authorized and issued portable telephone on the Floor. Currently, the Exchange does not permit the use of portable telephones on its Floor. Thus, with the approval of the Exchange, a Floor broker would be permitted to engage in direct voice communication from the point of sale to an off-Floor location, such as a member firm's trading desk or the office of one of the broker's customers. Such communications would permit the broker to accept orders consistent with Exchange rules, provide status and oral execution reports as to orders previously received, as well as ''market look'' observations as are routinely transmitted from a broker's booth location today. Use of a portable telephone on the Exchange Floor other than one authorized and issued by the Exchange would continue to be prohibited.

Both incoming and outgoing calls would be allowed, provided the requirements of all other Exchange rules have been met. A broker would not be permitted to represent and execute any order received as a result of such voice communication unless the order was first properly recorded by the member and entered into the Exchange's Front End Systemic Capture (FESC) electronic database.[4] In addition, Exchange rules require that any Floor broker receiving orders from the public over portable phones must be properly qualified to do direct access business under Exchange rules 342 and 345, among others.[5]

The Exchange would not permit portable communications at the point of sale for orders in Investment Company Units (as defined in Section 703.16 of the Listed Company Manual), also known as Exchange-Traded Funds (ETFs), since orders in ETFs can first be executed and then entered into FESC.[6] Technical restraints would be developed to implement this policy, thus preventing the use of portable phones where ETFs currently trade.

This proposal would be implemented as a six-month pilot from the date of Commission approval with a commitment by the Exchange to complete within three months of Commission approval a study of communications on the Exchange Floor, pursuant to a recommendation of an Independent Consultant retained by the Exchange.[7]

Under the current policy, an off-Floor customer can communicate with a broker in a trading crowd only in an indirect, second-hand fashion by calling a broker's booth and using the booth clerk as an intermediary. The Exchange believes that eliminating the current restriction against the use of portable telephones would enable the Exchange to provide more direct, efficient access to its trading crowds and customers, increase the speed of transmittal of orders and the execution of trades, and provide an enhanced level of service to customers in an increasingly competitive environment.[8] By enabling customers to speak directly to a Floor broker in a trading crowd on an Exchange authorized and issued portable telephone, the proposed rule change would, in the Exchange's view, expedite and make more direct the free flow of information which today has to be transmitted somewhat more circuitously via the broker's booth.

Specialists are subject to separate restrictions in NYSE rule 36 on their ability to engage in voice communications from the specialist post to an off-Floor location.[9] The Exchange's proposed amendment to NYSE rule 36 would not apply to specialists, who would continue to be prohibited from speaking from the post to upstairs trading desks or customers.

2. Statutory Basis

The Exchange represents that the statutory basis for this proposed rule change is the requirement under section 6(b)(5) of the Act[10] that an exchange have rules that are designed to promote just and equitable principles of trade, to

[4] *See* Securities Exchange Act Release No. 43689 (December 7, 2000), 65 FR 79145 (December 18, 2000) (SR–NYSE–98–25). *See also* Securities Exchange Act Release No. 44943 (October 16, 2001), 66 FR 53820 (October 24, 2001) (SR–NYSE–2001–39) (discussing certain exceptions to FESC, such as orders to offset an error, or a bona fide arbitrage, which may be entered within 60 seconds after a trade is executed).

[5] For more information regarding Exchange requirements for conducting a public business on the Exchange Floor, *see* Information Memo 01–41 (November 21, 2001), Information Memo 01–18 (July 11, 2001) (available on *www.nyse.com/regulation/regulation.html*), and Information Memo 91–25 (July 8, 1991).

[6] *See* Securities Exchange Act Release No. 45246 (January 7, 2002), 67 FR 1527 (January 11, 2002) (SR–NYSE–2001–52) (discussing an exception to FESC that allows ETFs to be entered within 90 seconds of execution). *See also* Securities Exchange Act Release No. 46713 (October 23, 2002), 67 FR 66033 (October 29, 2002) (SR–NYSE–2002–48) (extending the exception until January 5, 2004).

[7] *See In the Matter of New York Stock Exchange,* 70 S.E.C. Docket 106, Release No. 41574, 1999 WL 430863 (June 29, 1999).

[8] *See* Securities Exchange Act Release No. 43836 (January 11, 2001), 66 FR 6727 (January 22, 2001) (SR–PCX–00–33) (discussing and approving the Pacific Exchange, Inc.'s proposal to remove the current prohibition against Floor brokers' use of cellular or cordless phones to make calls to persons located off the trading floor).

[9] *See* Securities Exchange Act Release No. 46560 (September 26, 2002), 67 FR 62088 (October 3, 2002) (SR–NYSE–00–31) (discussing restrictions on specialists' communications from the post).

[10] 15 U.S.C. 78f(b)(5).

remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest. The Exchange believes that the amended proposed change to NYSE rule 36 supports the mechanism of free and open markets by providing for increased means by which communications to and from the Floor of the Exchange may take place.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change, as amended, will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

The Exchange has neither solicited nor received written comments on the proposed rule change.

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 Exchange consents, the Commission will:

(A) By order approve the 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, including whether the proposed rule change, as amended, is consistent with the Act. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 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 in the Commission's Public Reference Room. Copies of such filing will also be available for inspection and copying at the principal office of the Exchange. All should refer to File No. SR–NYSE–2002–11 and should be submitted by February 18, 2003.

For the Commission by the Division of Market Regulation, pursuant to delegated authority.[11]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 03–1879 Filed 1–27–03; 8:45 am]

BILLING CODE 8010–01–P

[11] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–47215; File No. SR–NYSE–2002–50]

Self-Regulatory Organizations; Notice of Filing of Proposed Rule Change and Amendment No. 1 Thereto by the New York Stock Exchange, Inc. To Adopt Amendments to Exchange Rules 450 (''Restrictions on Giving of Proxies''), 451 (''Transmission of Proxy Material''), 452 (''Giving Proxies by Member Organizations''), and 465 (''Transmission of Interim Reports and Other Material'')

January 17, 2003.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and rule 19b–4 thereunder,[2] notice is hereby given that on October 16, 2002, the New York Stock Exchange, Inc. (''NYSE'' or ''Exchange'') 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 NYSE. On December 19, 2002, the NYSE submitted Amendment No. 1 to the proposed rule change.[3] The Commission is publishing this notice to solicit comments on the proposed rule change, as amended, from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The NYSE is proposing to amend NYSE rule 450 (''Restriction on Giving of Proxies''), NYSE rule 451 (''Transmission of Proxy Material''), NYSE rule 452 (''Giving Proxies by Member Organizations''), and NYSE rule 465 (''Transmission of Interim Reports and Other Material'') to allow authorized state-registered investment advisers to receive and vote proxy materials on behalf of beneficial owners. The text of the proposed rule change is below. Proposed new language is in italics; deleted language is in brackets.

Restriction on Giving of Proxies

Rule 450. No member organization shall give or authorize the giving of a proxy to vote stock registered in its name, or in the name of its nominee, except as required or permitted under the provisions of rule 452, unless such member organization is the beneficial owner of such stock. Notwithstanding the foregoing,

(1) Any member organization, designated by a named fiduciary as the investment manager of stock held as assets of an ERISA Plan that expressly grants discretion to the investment manager to manage, acquire, or dispose of any plan asset and which has not expressly reserved the proxy voting right for the named fiduciary, may vote the proxies in accordance with its ERISA Plan fiduciary responsibilities; and

(2) Any person registered as an investment adviser, *either* under the Investment Advisers Act of 1940 *or under the laws of a state,*[4] who exercises investment discretion pursuant to an advisory contract for the beneficial owner and has been designated in writing by the beneficial owner to vote the proxies for stock which is in the possession or control of the member organization, may vote such proxies.

Transmission of Proxy Material

Rule 451. (a) Whenever a person soliciting proxies shall furnish a member organization:

(1) [C]*c*opies of all soliciting material which such person is sending to registered holders, and

(2) satisfactory assurance that [he] *the person* will reimburse such member organization for all out-of-pocket expenses, including reasonable clerical expenses, incurred by such member organization in connection with such solicitation,

such member organization shall transmit to each beneficial owner of stock which is in its possession or

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* letter from Darla Stuckey, Corpoate Secretary, NYSE, to Nancy Sanow, Assistant Director, Division of Market Regulation, Commission, dated December 19, 2002 (''Amendment No. 1''). In Amendment No. 1, the NYSE revised the first footnote of proposed NYSE rule 451 to define the term ''state'' by reference to the Investment Advisers Act of 1940, instead of the Securities Exchange Act of 1934

[4] *The term ''state'' as used herein shall have the meaning given to such term in Section 3(a)(16) of the Investment Advisers Act of 1940, and as such term may be amended from time to time therein.*

control or to an investment advisor, registered *either* under the Investment Advisers Act of 1940 *or under the laws of a state,* who exercises discretion pursuant to an advisory contract for the beneficial owner and has been designated in writing by the beneficial owner of such stock (hereinafter ''designated investment adviser'') to receive soliciting material in lieu of the beneficial owner, the furnished material; and

(b) No Change.

* * * * *

Giving Proxies by Member Organizations

Rule 452. A member organization shall give or authorize the giving of a proxy for stock registered in its name, or in the name of its nominee, at the direction of the beneficial owner. If the stock is not in the control or possession of the member organization, satisfactory proof of the beneficial ownership as of the record date may be required.

Voting Member Organization Holdings as Executor, etc.

A member organization may give or authorize the giving of a proxy to vote any stock registered in its name, or in the name of its nominee, if such member organization holds such stock as executor, administrator, guardian, trustee, or in a similar representative or fiduciary capacity with authority to vote.

Voting Procedure Without Instructions

A member organization which has transmitted proxy soliciting material to the beneficial owner of stock or to an investment adviser, registered *either* under the Investment Advisers Act of 1940 *or under the laws of a state,* who exercises investment discretion pursuant to an advisory contract for the beneficial owner and has been designated in writing by the beneficial owner of such stock (hereinafter ''designated investment adviser'') to receive soliciting material in lieu of the beneficial owner and solicited voting instructions in accordance with the provisions of rule 451, and which has not received instructions from the beneficial owner or from the beneficial owner's designated investment adviser by the date specified in the statement accompanying such material, may give or authorize the giving of a proxy to voted such stock, provided the person in the member organization giving or authorizing the giving of the proxy has no knowledge of any contest as to the action to be taken at the meeting and provided such action is adequately disclosed to stockholders and does not include authorization for a merger, consolidation or any other matter which may affect substantially the rights or privileges of such stock.

* * * * *

Transmission of Interim Reports and Other Material

Rule 465. A member organization, when so requested by a company, and upon being furnished with:

(1) Copies of interim reports of earnings or other material being sent to stockholders, and

(2) Satisfactory assurance that it will be reimbursed by such company for all out-of-pocket expenses, including reasonable clerical expenses, shall transmit such reports or material to each beneficial owner of stock of such company held by such member organization and registered in a name other than the name of the beneficial owner unless the beneficial owner has instructed the member organization in writing to transmit such reports or material to a designated investment adviser, registered *either* under the Investment Advisers Act of 1940 *or under the laws of a state,* who exercises investment discretion pursuant to an advisory contract for such beneficial owner.

* * * * *

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 Exchange 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 Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

I. Purpose

Background and Prior Amendments

On August 25, 1994, the Commission approved amendments to Exchange rules related to voting of proxies and transmission of proxy and related issuer material.[5] The affected rules were NYSE rule 450 (''Restrictions on Giving of Proxies''), NYSE rule 451 (''Transmission of Proxy Material''), NYSE rule 452 (''Giving Proxies by Member Organizations''), and NYSE rule 465 (''Transmission of Interim Reports and Other Material'').

The 1994 amendments gave beneficial owners the ability to authorize investment advisers registered under the Investment Advisers Act of 1940 (''Advisers Act'')[6] who exercise investment discretion pursuant to an advisory contract and who have been designated to the member organization in writing by the beneficial owner, to receive proxy soliciting materials, annual reports and other related issuer material and to vote proxies for the beneficial owners of securities. In other words, the amendments permitted member organizations to comply with such duly authorized customer requests, provided the designated adviser was registered under the Advisers Act.

Prior to these amendments, Exchange rules required transmission of proxy and related materials by the member organization to each beneficial owner of stock held in the member organization's possession and control. In fact, pre-amendment NYSE rule 451 explicitly required that proxy materials be sent to a beneficial owner even if such owner had instructed the member organization not to do so.

The National Securities Market Improvement Act Amendments

Effective July 1997, the Commission adopted new rules and rule amendments under the Advisers Act to implement provisions under title III of the National Securities Markets Improvement Act of 1996 that reallocate regulatory responsibilities for investment advisers between the Commission and the states.[7] Generally, title III (a/k/a The Investment Advisers Supervision Coordination Act or the ''Coordination Act'') provides for Commission regulation of advisers with $25 million or more of assets under management, and state regulation of advisers with less than $25 million of assets under management.

Specifically, new section 203A(a) of the Advisers Act[8] provides that an investment adviser that is regulated or required to be regulated as an investment adviser in the state in which it maintains its principal office and place of business is prohibited from

[5] *See* Exchange Act Release No. 34596, 59 FR 45050 (August 31, 1994) and NYSE Information Memo Number 94–41 (September 7, 1994).

[6] 15 U.S.C. 80b.

[7] 62 FR 28112 (May 22, 1997); Release No. IA–1633, File No. S7–31–96.

[8] 15 U.S.C. 80b–3a.

registering with the Commission unless the adviser:

(i) Has assets under management of not less than $25 million (or such higher amount as the Commission may, by rule, deem appropriate), or

(ii) Is an adviser to an investment company registered under the Investment Company Act of 1940.

The Proposed Amendments

The provisions of the Coordination Act have been estimated to reduce by two-thirds the number of advisers eligible to register with the Commission.

Consequently, a large number of investment advisers (those with less than $25 million under management) who exercise investment discretion pursuant to an advisory contract, and have been designated to the member organization in writing by the beneficial owner to receive and vote proxy materials, are no longer authorized to do so under NYSE Rules. NYSE believes that amending NYSE rules 450, 451, 452, and 465 to allow such authorization to be extended to advisers registered under state law would allow for the reasonable customer expectation that duly designated advisers, subject to regulation, be permitted to receive and vote proxy materials on their behalf.

The Exchange represents that the proposed amendments are consistent with a proposed rule change recently filed by the National Association of Securities Dealers, Inc. with the Commission.[9]

2. Statutory Basis

NYSE believes that the basis under the Exchange Act for this proposed rule change is the requirement under section 6(b)(5) of the Act [10] that an Exchange have rules that are designed to promote just and equitable principles of trade, to remove impediments to and to perfect the mechanism of a free and open market and a national market system and, in general, to protect investors and the public interest.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange believes that the proposal does not impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

Written comments were neither solicited nor received.

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, including whether the proposed rule change is consistent with the Act. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609. 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 in the Commission's Public Reference Room. Copies of such filing will also be available for inspection and copying at the principal office of the NYSE. All submissions should refer to the file number in the caption above and should be submitted by February 18, 2003.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[11]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 03–1881 Filed 1–27–03; 8:45 am]

BILLING CODE 8010–01–P

[9] *See* Exchange Act Release No. 47214 (January 17, 2003).

[10] 15 U.S.C. 78f(b)(5).

[11] 17 CFR 200.30–3(a)(12).

SMALL BUSINESS ADMINISTRATION

[Declaration of Disaster #3459]

State of Texas (Amendment #7)

In accordance with a notice received from the Federal Emergency Management Agency, dated January 16, 2003, the above numbered declaration is hereby amended to extend the deadline for filing applications for physical damages as a result of this disaster to January 31, 2003.

All other information remains the same, *i.e.*, the deadline for filing applications for economic injury is August 5, 2003.

(Catalog of Federal Domestic Assistance Program Nos. 59002 and 59008).

Dated: January 17, 2003.

Herbert L. Mitchell,

Associate Administrator for Disaster Assistance.

[FR Doc. 03–1923 Filed 1–27–03; 8:45 am]

BILLING CODE 8025–01–P

DEPARTMENT OF STATE

[Public Notice 4223]

Secretary of State's Advisory Committee on Private International Law: Study Group on Reciprocal Enforcement of Child Support Obligations; Notice of Meetings

There will be a public meeting of a Study Group on International Child Support of the Secretary of State's Advisory Committee on Private International Law, on Wednesday, February 5, 2003, from 1 p.m. to 4 p.m. at the Hyatt Regency Capitol Hill, 400 New Jersey Avenue, NW., Washington, DC (Columbia Room, Ballroom level).

The purpose of this meeting is to assist the Department of State and the Office of Child Support Enforcement of the Department of Health and Human Services in preparing for the upcoming negotiation, under the auspices of the Hague Conference on Private International Law, of a new international convention on the international recovery of child support and other forms of family maintenance. The first session of this negotiation is scheduled for May 2003 in The Hague. Documents relevant to this project can be found on the web site of the Hague Conference (*www.hcch.net*).

The Study Group meetings are open to the public up to the capacity of the meeting rooms. Interested persons are invited to attend and to express their views. Persons who wish to have their views considered are encouraged, but not required, to submit written

comments in advance of the meeting. Written comments should be submitted by e-mail to Mary Helen Carlson at *carlsonmh@ms.state.gov*. All comments will be made available to the public by request to Ms. Carlson via e-mail or by phone (202–776–8420).

Mary Helen Carlson,

Office of the Legal Adviser for Private International Law, Department of State.

[FR Doc. 03–1890 Filed 1–27–03; 8:45 am]

BILLING CODE 4710–08–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

Honoring Tickets of National Airlines Pursuant to the Requirements of the Section 145 of the Aviation and Transportation Security Act

On November 14, 2002, the Department of Transportation issued a notice providing guidance for airlines and the traveling public regarding the obligation of airlines under section 145 of the Aviation and Transportation Security Act, Pub. L. 107–71, 115 Stat. 645 (November 19, 2001) (''Act''), to transport passengers of airlines that have ceased operations due to insolvency or bankruptcy. That notice, issued after National Airlines' November 6, 2002, cessation of operations, followed a similar notice issued August 8, 2002, after Vanguard Airlines' July 2002 cessation of service. Both notices were intended to provide immediate guidance in response to numerous complaints from ticketed passengers and inquiries from airlines. In addition, the November 14 notice also requested comments from airlines and the traveling public about the cost to carriers of transporting passengers of carriers that had ceased operations. The purpose of this notice is to respond to those comments.

Section 145 requires, in essence, that airlines operating on the same route as an insolvent carrier that has ceased operations transport the ticketed passengers of the insolvent carrier ''to the extent practicable.'' Our earlier notices mentioned several factors that we would look to in determining whether airlines were complying with section 145.[1] We stated, among other things, our preliminary view that, at a minimum, section 145 requires that passengers holding valid confirmed tickets, whether paper or electronic, on an insolvent or bankrupt carrier be transported by other carriers who operate on the route for which the passenger is ticketed on a space-available basis, without significant additional charges.[2] We made clear in our guidance, however, that we did not believe that Congress intended to prohibit carriers from recovering from accommodated passengers the amounts associated with the actual cost of providing such transportation. We stated that we did not foresee that such costs would exceed $25.00, an amount that we made clear was an estimate of the magnitude of the additional direct costs carriers might incur in transporting affected passengers on a standby basis.[3]

In our November 14 notice, in response to informal concerns raised by several carriers that our $25.00 cost estimate is too low, we formally requested that any airline or person who believes that the Department's estimate of $25.00 is either insufficient, or is more than necessary to cover the direct costs of accommodating ticketed passengers on a space-available basis, contact the Department and provide written comments and cost evidence in support of that position. Our formal request for written comments was made after complaining carriers had failed to respond to our earlier, informal requests for such information, and after reports that consumers had been, at least initially, charged far in excess of $25.00 for transportation.[4]

Delta Airlines (''Delta''), American Airlines (''American''), America West Airlines (''America West''), and United Airlines (''United'') filed comments in response to our request. Unfortunately, none of those carriers provided information responsive to our request or otherwise demonstrating costs in excess of $25.00 each way for space-available transportation. Instead, Delta and American chose to argue that the Department has no ratemaking authority, and the Department's suggestion that, for purposes of section 145, $25.00 each way is a reasonable estimate of the cost to a carrier of providing alternate, space-available transportation constitutes ratemaking.[5] They both further argue that, even if the Department had authority under section 145 to review the reasonableness of fees charged to accommodate another airline's passengers, the marketplace should dictate the amount of that charge. American argues that in a deregulated environment passengers should assume the risk in booking with a financially weak carrier and, according to American and Delta, an airline's ''standard reticketing fee,'' which is charged to fare-paying passengers who, under terms of their contract of carriage with the airline, voluntarily change their travel plans, is what the marketplace dictates. The carriers further argue that charging passengers of another airline that has ceased operations under section 145 an amount less than that ''standard reticketing fee'' is unfair to their fare-paying passengers. American also asserts in its comments that we have not adequately addressed its concerns over establishing the validity of tickets, especially electronic tickets, of passengers seeking reaccommodation under section 145.

America West and United both assert that their respective costs for providing alternate transportation on a space-available basis exceed $25.00 each way. Neither airline, however, provided information in support of that assertion, as requested by the Department. According to America West, the costs associated with transporting passengers of an airline that has ceased operations involve consideration of delays, security and baggage screening, and fraud, and could vary by market, time of service, and season. Accordingly, the carrier states, it did not have sufficient time to document all such costs. It states that instead, it elected to assess such passengers the same fare it would charge employees for friends and family members, under its ''buddy pass'' system, which permits those persons to

[1] Failure by an airline to comply with section 145 may constitute an unfair and deceptive practice violation of 49 U.S.C. 41712.

[2] We further pointed out that, under section 145, passengers whose transportation has been interrupted have 60 days after the date of the service interruption to make alternative arrangements with an airline for that transportation.

[3] We pointed out that examples of such costs include the cost of rewriting tickets, providing additional onboard meals, and the incremental fuel costs attributable to transporting an additional passenger.

[4] Long before formal comments were requested, Department staff had informally advised carriers that expressed concerns about this guidance that, to the extent they experienced and could document reasonable direct costs in excess of $25.00, they should be entitled to recover such costs under the statute. At that time, Department staff specifically requested each airline that had expressed concern to provide evidence demonstrating that its reasonable direct costs exceeded the estimated $25.00 amount. No airline provided any documentation in response to that informal request. A few airlines also expressed separate concerns about difficulties in verifying confirmed reservations of passengers holding electronic tickets, in which case a hard-copy ticket would not be available. Department staff suggested it would be appropriate to require such passengers to provide proof of payment and confirmation, such as receipts and printed itineraries.

[5] Both carriers have challenged the Department's efforts to provide guidance regarding section 145 in the U.S. Court of Appeals for the District of Columbia. *See Delta Air Lines, Inc. and American Airlines, Inc.* v. *U.S. Department of Transportation,* Case No. 02–1309 (D.C. Cir. filed October 8, 2002).

travel on a space-available basis.[6] United states that its ''preliminary'' review persuades it that its costs exceed $25.00 each way but, due a lack of time in the immediate aftermath of the Vanguard and National shutdowns for detailed cost analyses and in view of the small number of passengers involved, it elected as a matter of policy to charge affected passengers $25.00 each way. United states that, because it has chosen to abide by the suggested $25.00 amount, it does not wish to burden itself with providing cost information at this time. United points out, however, that a variety of factors may affect its costs in any future instance where section 145 comes into play, such as fuel costs, the number of passengers affected, and the itineraries involved, such as domestic versus international travel. United states that it may, in some instances, impose a charge higher than $25.00 each way but adds that it will advise the Department before doing so.

We see no reason, based on the comments submitted, to change our guidance with respect to the implementation by carriers of the requirements of section 145. We find particularly unpersuasive Delta's and American's argument that we lack the authority to provide any guidance with respect to section 145, and that our actions are unlawful ratemaking. Equally unpersuasive is the carriers' argument that the so-called ''marketplace'' rate, *i.e.* whatever rate those carriers elect to charge, is what Congress intended in requiring carriers to accommodate displaced passengers ''to the extent practicable.''[7]

We are not, as suggested by Delta and American, setting rates. As we stated in our earlier notices, in requiring carriers to accommodate passengers of a failed carrier ''to the extent practicable,'' it is reasonable to assume that Congress did not intend to prohibit carriers from recovering minimal amounts associated with the actual cost of providing alternate transportation.[8] Adoption of Delta's and American's ''marketplace'' charge argument would render section 145 meaningless. Prior to enactment of section 145, airlines were free to transport passengers of a carrier that had ceased operations on a standby or confirmed basis at whatever charge they deemed appropriate. If, as Delta and American suggest, Congress intended to permit carriers to continue to charge passengers of carriers that had ceased operations a so-called ''marketplace'' rate, *i.e.*, whatever rate the carriers deem appropriate, then Congress need not have enacted section 145 in the first place.[9]

Furthermore, the carriers' argument that it is unfair to charge a section 145 passenger less than they charge their own passengers to be reticketed is inapposite. Some of American's and Delta's domestic passengers are assessed a ''standard reticketing fee'' under terms of their contract of carriage with the respective airline for the fare under which they were ticketed, but only after they have voluntarily changed their travel plans as provided in the contract of carriage. Such change fees are in large measure assessed not simply to recoup reticketing costs, but in order to differentiate one fare product from another, *i.e.*, as a ''penalty'' to affect passengers'' purchasing behavior. Indeed, some fare-paying passengers of American and Delta may change their travel plans at will and are not required to pay any ''reticketing'' fee at all.

We believe that the airlines'' normal pricing practices provide powerful evidence that the carriers' domestic ''standard reticketing fee'' of $100 far exceeds any costs of providing that service.[10] Each day, tens of thousands of Delta and American passengers are charged less than $100 each way, including taxes, by those carriers for their air transportation. Indeed, statistics filed with the Department by Delta show that in the second quarter of 2002, more than 3 million of Delta's fare-paying passengers, about 36 percent, paid less than $100 each way to travel on the carrier.[11] Similarly, statistics filed with the Department by American show that, for the same period, more than 2.3 million passengers, about 28 percent, paid less than $100 each way to travel on the carrier. Thus, it appears that unless those two carriers are offering a large percentage of their seat inventory at prices below their cost, there is no relation between the ''standard reticketing fee'' and Delta's or American's cost to carry a passenger.[12]

American also asserts that we have not adequately addressed its concerns over establishing the validity of tickets, especially electronic tickets, of passengers seeking to be reaccommodated under section 145. We disagree. We continue to believe that, in the case of electronic tickets, it is reasonable for airlines to take steps to satisfy themselves of the *bona fides* of the ticketholder requesting alternate transportation. Our suggestion that it would be appropriate to require passengers to provide proof of payment and confirmation, such as receipts and printed itineraries, was not intended to be exclusive, but only an example of the types of steps that might be taken by a carrier to satisfy itself of the validity of a passenger's claim to transportation under section 145. We recognize that there may be instances in which, absent verification of the passenger's status by the failed carrier, an airline cannot confirm the validity of the passenger's claim to transportation under section 145. However, that fact does not require the conclusion that the only way in which to validate a passenger's status is through a paper ticket or access to the failed carrier's reservation system.

As we have made clear in our prior notices, we are sympathetic to carriers' concerns that they not suffer uncompensated additional expenses in transporting passengers pursuant to section 145. We are disappointed, however, that no carrier, particularly those raising the strongest objections about our prior notices, chose to provide

[6] We have reason to believe that such a system would result in charges far in excess of $25.00 each way. Soon after National ceased operations, America West orally advised a Department staff member posing as a National passenger that its charge for transportation from Las Vegas to Chicago and return would be $168.50. At that time, the walk-up fare for any passenger was $276. Upon further inquiry by the Department, America West stated that this system was no longer being used in connection with section 145 and that it was assessing National passengers a $25 charge each way for standby travel.

[7] Section 145 cannot be viewed in a vacuum. Congress enacted section 145 in an effort, at least in part, to ensure some measure of relief to aviation consumers who might be adversely affected by the serious economic consequences on airlines resulting from the terrorist attacks on September 11, 2001. At the same time it imposed these new duties on airlines, it also provided them with compensation totaling billions of dollars.

[8] However, since section 145 is silent on the issue of whether any fees may be assessed for transporting passengers of a carrier that has ceased service on a route, another possible interpretation might be that Congress intended that carriers not charge passengers at all for carriage under section 145.

[9] For this same reason, American's argument that Congress intended that passengers should assume the risk in booking with a financially weak carrier would, if adopted, necessarily render section 145 meaningless.

[10] We note that both American and Delta assess a ''standard reticketing fee'' of $150 for international travel.

[11] 11 This information is based on Passenger Origin-Destination Survey data filed with the Department. Most passengers purchase tickets on a round trip basis.

[12] In addition, the position asserted in the comments filed by Delta and American is inconsistent with information provided to us by those airlines during our reviews of competition issues. In those cases, and in court proceedings under the antitrust laws, airlines routinely contend that their incremental cost of carrying an additional passenger is minimal, being made up largely of Computer Reservations System or other booking fees, credit card fees, commissions, marketing fees, and minor costs for fuel and food. In fact, we have recently been advised by a Delta official that the variable cost of accepting an additional passenger is $25 or less.

us with any information on their direct costs of carrying passengers on a space-available basis pursuant to section 145.

Notwithstanding our public invitation to all affected parties, there is no evidence in any of the comments submitted to us indicating that our suggested charge of $25.00 each way to accommodate passengers under section 145 is unreasonable. As we informally made clear to every carrier that inquired at the outset, and as is plain from our November 14 notice requesting comments on the cost issue, we understand that costs may vary by carrier. We also agree with the commenters who suggested that the cost to a particular carrier of complying with section 145 may be affected by a variety of factors, including the number of passengers, the current fuel costs to carriers, and the markets and itineraries involved. We note that, consistent with our statutory responsibilities, including those under 49 U.S.C. 41712, it is important in implementing section 145 to avoid uncertainty and unnecessary harm to the industry and the public. We therefore intend to continue to monitor this situation and work with all carriers informally to ensure that the Congressional intent of section 145 is effectuated in any given situation.

Questions regarding this notice may be addressed in writing to Dayton Lehman, Deputy Assistant General Counsel, Office of Aviation Enforcement and Proceedings, 400 7th St., SW., Washington, DC 20590, or he may be contacted by telephone at (202) 366–9342.

An electronic version of this document is available on the World Wide Web at *http://dms.dot.gov/reports*.

Dated: January 23, 2003.

Read C. Van de Water,

Assistant Secretary for Aviation and International Affairs.

[FR Doc. 03–2007 Filed 1–24–03; 11:13 am]

BILLING CODE 4910–62–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

Aviation Proceedings, Agreements Filed the Week Ending January 17, 2003

The following Agreements were filed with the Department of Transportation under the provisions of 49 U.S.C. 412 and 414. Answers may be filed within 21 days after the filing of the application.

Docket Number: OST–2003–14260.

Date Filed: January 14, 2003.

Parties: Members of the International Air Transport Association.

Subject: CTC COMP 0438 dated 14 January 2003. Mail Vote 262—Resolution 035. Unethical Disclosure of Information (New). Intended effective date: 1 April 2003.

Docket Number: OST–2003–14298.

Date Filed: January 16, 2003.

Parties: Members of the International Air Transport Association.

Subject:

PTC COMP 1000 dated 17 January 2003.

Mail Vote 263—Resolution 011a (Amending).

Mileage Manual Non-TC Member/Non-IATA Carrier Sectors.

Intended effective date: 1 February 2003 for implementation, 1 April 2003.

Dorothy Y. Beard,

Chief, Docket Operations and Media Management, Federal Register Liaison.

[FR Doc. 03–1870 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–62–P

DEPARTMENT OF TRANSPORTATION

Coast Guard

[USCG–2003–14326]

Towing Safety Advisory Committee

AGENCY: Coast Guard, DOT.

ACTION: Notice of meeting.

SUMMARY: The Towing Safety Advisory Committee's (TSAC) Working Group on Regulation Review will meet to discuss various issues relating to current U.S. Coast Guard regulations as they pertain to towing vessels. The meeting will be open to the public.

DATES: The TSAC Working Group will meet on Tuesday, February 18, 2003, from 1 p.m. to 4 p.m. and on the following day, Wednesday, February 19, 2003, from 8 a.m. to 12 noon. The meeting may close early if all business is finished. Written material and requests to make oral presentations should reach the Coast Guard on or before February 12, 2003. Requests to have a copy of your material distributed to each member of the Working Group should reach the Coast Guard on or before February 7, 2003.

ADDRESSES: The Working Group will meet in room 6319, U.S. Coast Guard Headquarters, 2100 Second Street SW., Washington, DC. Send written material and requests to make oral presentations to Mr. Gerald P. Miante, Commandant (G–MSO–1), Room 1210, U.S. Coast Guard Headquarters, 2100 Second Street SW., Washington, DC 20593–0001. This notice is available on the Internet at *http://dms.dot.gov.*

FOR FURTHER INFORMATION CONTACT: Mr. Gerald P. Miante, Assistant Executive Director of TSAC, telephone 202–267–0214, or fax 202–267–4570, or e-mail at: *gmiante@comdt.uscg.mil.*

SUPPLEMENTARY INFORMATION: Notice of the meeting is given under the Federal Advisory Committee Act, 5 U.S.C. App. 2.

Agenda of Meeting

The agenda tentatively includes the following:

1. Review current U.S. Coast Guard regulatory requirements pertaining to uninspected towing vessels;

2. Assess the adequacy of these existing regulations;

3. Identify any gaps in these regulations and research where else those gaps may be addressed—such as in voluntary or non-regulatory programs; and

4. Ascertain the best method to address any gaps not addressed in regulatory or non-regulatory products.

Procedural

The meeting is open to the public. Please note that the meeting may close early if all business is finished. At the Chair's discretion, members of the public may make oral presentations during the meeting. If you would like to make an oral presentation at the meeting, please notify the Assistant Executive Director no later than February 12, 2003. Written material for distribution at the meeting should reach the Coast Guard no later than February 7, 2003. If you would like a copy of your material distributed to each member of the Working Group in advance of the meeting, please submit 15 copies to Mr. Miante at the address in **ADDRESSES,** or an electronic version to the e-mail address in **FOR FURTHER INFORMATION CONTACT,** no later than February 7, 2003.

Information on Services for Individuals With Disabilities

For information on facilities or services for individuals with disabilities or to request special assistance at the meeting, contact the Assistant Executive Director as soon as possible.

Dated: January 22, 2003.

Joseph J. Angelo,

Director of Standards, Marine Safety, Security & Environmental Protection.

[FR Doc. 03–1911 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Notice of Intent To Rule on Application 03–09–C–00–CMX To Impose and Use the Revenue From a Passenger Facility Charge (PFC) at Houghton County Memorial Airport, Hancock, 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 Houghton County Memorial Airport under the provisions of the 48 U.S.C. 40117 and part 158 of the Federal Aviation Regulations (14 CFR part 158).

DATES: Comments must be received on or before February 27, 2003.

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. The application may be reviewed in person at this location.

In addition, one copy of any comments submitted to the FAA must be mailed or delivered to Ms. Sandra D. LaMothe, Airport Manager, Houghton County Memorial Airport at the following address: Houghton County Memorial Airport, 23810 Airpark Boulevard, Suite 113, Hancock, Michigan 49913.

Air carriers and foreign air carriers may submit copies of written comments previously provided to the County of Houghton under § 158.23 of Part 158.

FOR FURTHER INFORMATION CONTACT: Ms. Arlene B. Draper, Program Manager, Federal Aviation Administration, Detroit Airports District Office, Willow Run Airport, East, 8820 Beck Road, Belleville, Michigan 48111 (734–487–7282). 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 Houghton County Memorial Airport under the provisions of 49 U.S.C. 40117 and part 158 of the Federal Aviation Regulations (14 CFR part 158).

On January 6, 2003, the FAA determined that the application to impose and use the revenue from a PFC submitted by the County of Houghton was substantially complete within the requirements of § 158.25 of part 158. The FAA will approve or disapprove the application, in whole or in part, not later than May 2, 2003.

The following is a brief overview of the application.

Level of the proposed PFC: $3.00.

Proposed charge effective date: September 1, 2005.

Proposed charge expiration date: May 1, 2007.

Total estimated PFC revenue: $104,266.

Brief description of proposed projects: Acquire snow removal equipment, access road lighting, directional and entrance road signage, new electrical service to Aircraft Rescue and Fire Fighting (ARFF) building, rehabilitate public address system in passenger terminal, terminal landside rehabilitation, terminal apron pavement crack sealing, terminal airside entrance rehabilitation, thermal imaging cameras for ARFF vehicles, Unicom radio procurement, electrical transformer screen wall, runway 13 protection zone hazard removal, terminal bathroom rehabilitation, PFC application reimbursement, security fencing with perimeter road.

Class or classes of air carriers, which the public agency has requested to be required to collect PFCs: The County of Houghton has not requested approval to exclude a class or classes of carriers from the PFC collection requirements.

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 Houghton.

Issued in Des Plaines, Illinois on January 15, 2003.

Mark McClardy,

Manager, Planning and Programming, Airports Division, Great Lakes Region.

[FR Doc. 03–1877 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Notice of Passenger Facility Charge (PFC) Approvals and Disapprovals

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Monthly Notice of PFC approvals and disapprovals. In December 2002, there were seven applications approved. This notice also includes information on one application, approved in October 2002, inadvertently left off the October 2002 notice. Additionally, four approved amendments to previously approved applications are listed.

SUMMARY: The FAA publishes a monthly notice, as appropriate, of PFC approvals and disapprovals under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Pub. L. 101–508) and Part 158 of the Federal Aviation Regulations (14 CFR part 158). This notice is published pursuant to paragraph (d) of § 158.29.

PFC Application Approved

Public Agency: City of Worland, Wyoming.

Application Number: 02–01–C–00–WRL.

Application Type: Impose and use a PFC.

PFC Level: $4.50.

Total PFC Revenue Approved in This Decision: $70,500.

Earliest Charge Effective Date: January 1, 2003.

Estimated Charge Expiration Date: March 1, 2008.

Class of Air Carriers not Required To Collect PFC's: None.

Brief Description of Projects Approved for Collection and Use: Preliminary design engineering for runway extension, road, and canal relocation.

Acquire land for runway extension and land use protection.

Relocate obstructions—Highland Hanover Canal and county road.

Brief Description of Disapproved Project; Rehabilitate and shift runway 16/34.

Determination: As proposed, the project does not meet the requirement that it will be implemented within 2 years of approval. In addition, the proposed financial plan required Airport Improvement Program discretionary funds that the FAA did not support, thus raising questions about the financial viability of the project.

Decision Date: October 10, 2002.

FOR FURTHER INFORMATION CONTACT: Christopher Schaffer, Denver Airports District Office, (303) 342–1258.

Public Agency: Niagara Frontier Transportation Authority, Buffalo, New York.

Application Number: 02–04–C–00–BUF.

Application Type: Impose and use a PFC.

PFC Level: $3.00

Total PFC Revenue Approved in This Decision: $23,290,853.

Earliest Charge Effective Date: October 1, 2005.

Estimated Charge Expiration Date: January 1, 2010.

Class of Air Carriers not Required To Collect PFC's: Air taxi/commercial operators filing FAA Form 1800–31.

Determination: Approved. Based on information contained in the public agency's application, the FAA has determined that the approved class accounts for less than 1 percent of the total annual enplanements at Buffalo Niagara International Airport (BUF).

Brief Description of Projects Approved for Collection and Use at BUF: Relocation of security checkpoints.

Runway 14/32 safety improvement and relocation remote fuel dispensing facility.

Purchase safety equipment—aircraft rescue and firefighting/emergency response vehicles.

Passenger movement equipment.

Procurement of security equipment—vehicles.

Upgrade security badging system.

PFC planning and program administration.

Series 1999 debt service—east concourse.

Brief Description of Project Approved for Collection at BUF and Use at Niagara Falls International Airport: Purchase snow removal equipment.

Decision Date: December 11, 2002.

FOR FURTHER INFORMATION CONTACT: Eleanor Schifflin, Eastern Region Airports Division, (718) 553–3354.

Public Agency: City of Santa Barbara, California.

Application Number: 02–03–C–00–SBA.

Application Type: Impose and use a PFC.

PFC Level: $3.00

Total PFC Revenue Approved in This Decision: $2,001,560.

Earliest Charge Effective Date: May 1, 2005.

Estimated Charge Expiration Date: August 1, 2006.

Class of Air Carriers Not Required To Collect PFC's: Unscheduled Part 135 air taxi operators.

Determination: Approved. Based on information contained in the public agency's application, the FAA has determined that the approved class accounts for less than 1 percent of the total annual enplanements at Santa Barbara Municipal Airport.

Brief Description of Projects Approved For Collection and Use: Taxi B relocation. Taxiway M runway incursion project. New taxiway Q.

Brief Description of Projects Approved for Use: Extend runway safety areas. Extend taxiway A and safety areas.

Decision Date: December 12, 2002.

FOR FURTHER INFORMATION CONTACT: Kevin Flynn, Western Pacific Region Airports Division, (310) 725–3632.

Public Agency: Miami Dade Aviation Department, Miami, Florida.

Application Number: 02–04–C–00–MIA.

Application Type: Impose and use a PFC.

PFC Level: $4.50.

Total PFC Revenue Approved in This Decision: $2,420,400,341.

Earliest Charge Effective Date: March 1, 2003.

Estimated Charge Expiration Date: October 1, 2037.

Class of Air Carriers Not Required To Collect PFC's: Air taxi/commercial operators filing FAA Form 1800–31.

Determination: Approved. Based on information contained in the public agency's application, the FAA has determined that the approved class accounts for less than 1 percent of the total annual enplanements at Miami International Airport.

Brief Description of Projects Approved for Collection and Use: North terminal development. South terminal development.

Decision Date: December 12, 2002.

FOR FURTHER INFORMATION CONTACT: Miguel A. Martinez, Orlando Airports District Office, (407) 812–6331.

Public Agency: County of Jefferson, Beaumont, Texas.

Application Number: 02–04–C–00–BPT.

Application Type: Impose and use a PFC.

PFC Level: $4.50.

Total PFC Revenue Approved in This Decision: $149,300.

Earliest Charge Effective Date: March 1, 2005.

Estimated Charge Expiration Date: April 1, 2007.

Class of Air Carriers Not Required To Collect PFC's: None.

Brief Description of Projects Approved for Collection and Use: Conduct master plan update. Airport safety improvements. Acquire forward looking infrared system. PFC application and administration fees.

Brief Description of Withdrawn Project: Runway extension benefit cost analysis.

Determination: This project was withdrawn by the public agency on October 24, 2002.

Decision Date: December 17, 2002.

FOR FURTHER INFORMATION CONTACT: G. Thomas Wade, Southwest Region Airports Division, (817) 222–5613.

Public Agency: Duluth Airport Authority, Duluth, Minnesota.

Application Number: 02–06–C–00–DLH.

Application Type: Impose and use a PFC.

PFC Level: $4.50.

Total PFC Revenue Approved in This Decision: $901,280.

Earliest Charge Effective Date: April 1, 2003.

Estimated Charge Expiration Date: June 1, 2005.

Class of Air Carriers Not Required To Collect PFC'S: Non-scheduled Part 135 air taxi/commercial operators.

Determination: Approved. Based on information contained in the public agency's application, the FAA has determined that the approved class accounts for less than 1 percent of the total annual enplanements at Duluth International Airport.

Brief Description of Projects Approved for Collection and Use: Preparation of PFC application. Purchase replacement snow removal equipment. Construct snow removal equipment material storage and maintenance facility.

Decision Date: December 20, 2002.

FOR FURTHER INFORMATION CONTACT: Gordon Nelson, Minneapolis Airports District Office, (612) 712-4358.

Public Agency: South Jersey Transportation Authority, Egg Harbor Township, New Jersey.

Application Number: 03–02–C–00–ACY.

Application Type: Impose and use a PFC.

PFC Level: $3.00.

Total PFC Revenue Approved in This Decision: $1,573,274.

Earliest Charge Effective Date: September 1, 2005.

Estimated Charge Expiration Date: June 1, 2006.

Class of Air Carries Not Required To Collect PFC'S: Non-scheduled/on demand air carriers with less than 1,200 annual enplaned passengers filing FAA Form 1800–31.

Determination: Approved. Based on information contained in the public agency's application, the FAA has determined that the approved class accounts for less than 1 percent of the total annual enplanements at Atlantic City International Airport.

Brief Description of Projects Approved for Collection and Use: Rehabilitate taxiway B—phases I and II. Acquire snow removal equipment. Improve terminal building. Improvements to airport security systems—phase II. Terminal area study.

Brief Description of Projects Approved for Use: Construct snow

removal equipment building. ASR–9 relocation.

Brief Description of Projects Approved for Collection: Construct deicing containment facility. Environmental mitigation—design only.

Decision Date: December 20, 2002.

FOR FURTHER INFORMATION CONTACT: Dan Vornea, New York Airports District Office, (516) 227–3812.

Public Agency: Brown County, Green Bay, Wisconsin.

Application Number: 02–05–C–00–GRB.

Application Type: Impose and use a PFC.

PFC Level: $4.50.

Total PFC Revenue Approved in This Decision: $23,319,000.

Earliest Charge Effective Date: April 1, 2003.

Estimated Charge Expiration Date: January 1, 2016.

Class of Air Carriers Not Required To Collect PFC'S: Air taxi/commercial operators.

Determination: Approved. Based on information contained in the public agency's application, the FAA has determined that the approved class accounts for less than 1 percent of the total annual enplanements at Austin Straubel International Airport.

Brief Description of Project Approved for Collection and Use: Air carrier terminal expansion.

Decision Date: December 20, 2002.

FOR FURTHER INFORMATION CONTACT: Daniel J. Millenacker, Minneapolis Airports District Office, (612) 713–4359.

AMENDMENTS TO PFC APPROVALS

Amendment No. city, state	Amendment approved date	Original approved net PFC revenue	Amended approved net PFC revenue	Original estimated charge exp. date	Amended estimated charge exp. date
99–03–C–01–JAN Jackson, MS	12/04/02	$5,577,870	$11,925,562	04/01/03	02/01/07
98–03–C–01–BUR Burbank, CA.	12/20/02	84,481,000	0	06/01/10	10/01/01
*98–02–C–02–CRP Corpus Christi, TX	12/23/02	41,083,878	43,362,585	04/01/23	01/01/27
*99–03–C–01–TYR Tyler, TX	12/24/02	1,123,700	1,123,700	10/01/09	04/01/08

NOTE: The amendments denoted by an aterisk (*) include a change to the PFC level charged from $3.00 per enplaned passenger to $4.50 per enplaned passenger. For Corpus Christi, TX, this change is effective on March 1, 2003. For Tyler, TX, this change is effective on February 1, 2004.

Issued in Washington, DC on January 22, 2003.

Barry Molar,

Manager, Airports Financial Assistance Division.

[FR Doc. 03–1875 Filed 1–27–03; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Docket No. AB–6 (Sub–No. 397X)]

The Burlington Northern and Santa Fe Railway Company—Abandonment Exemption—in Pierce County, WA

The Burlington Northern and Santa Fe Railway Company (BNSF) has filed a notice of exemption under 49 CFR part 1152 subpart F—*Exempt Abandonments* to abandon a 0.24-mile line of railroad between milepost 28.10 and milepost 28.34 near McMillan, in Pierce County, WA. The line traverses United States Postal Service Zip Code 98374.

BNSF has certified that: (1) No local traffic has moved over the line for at least 2 years; (2) there is no overhead traffic to be rerouted; (3) no formal complaint filed by a user of rail service on the line (or by a state or local government entity acting on behalf of such user) regarding cessation of service over the line either is pending with the Surface Transportation Board (Board) or with any U.S. District Court or has been decided in favor of complainant within the 2-year period; and (4) the requirements at 49 CFR 1105.7 (environmental reports), 49 CFR 1105.8 (historic reports), 49 CFR 1105.11 (transmittal letter), 49 CFR 1105.12 (newspaper publication), and 49 CFR 1152.50(d)(1) (notice to governmental agencies) have been met.

As a condition to this exemption, any employee adversely affected by the abandonment shall be protected under *Oregon Short Line R. Co.—Abandonment—Goshen,* 360 I.C.C. 91 (1979). To address whether this condition adequately protects affected employees, a petition for partial revocation under 49 U.S.C. 10502(d) must be filed. Provided no formal expression of intent to file an offer of financial assistance (OFA) has been received, this exemption will be effective on February 27, 2003, unless stayed pending reconsideration. Petitions to stay that do not involve environmental issues,[1] formal expressions of intent to file an OFA under 49 CFR 1152.27(c)(2),[2] and trail use/rail banking requests under 49 CFR 1152.29 must be filed by February 7, 2003.[3] Petitions to reopen or requests for public use conditions under 49 CFR 1152.28 must be filed by February 18, 2003, with the Surface Transportation Board, 1925 K Street, NW., Washington, DC 20423–0001.

A copy of any petition filed with the Board should be sent to BNSF's representative: Michael Smith, Freeborn & Peters, 311 S. Wacker Dr., Suite 3000, Chicago, IL 60606–6677.

If the verified notice contains false or misleading information, the exemption is void *ab initio.*

BNSF has filed a separate environmental report which addresses the abandonment's effects, if any, on the environment and historic resources. SEA will issue an environmental assessment (EA) by January 31, 2003. Interested persons may obtain a copy of the EA by writing to SEA (Room 500, Surface Transportation Board, Washington, DC 20423–0001) or by calling SEA, at (202) 565–1552. (Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.) Comments on environmental and historic preservation matters must be filed within 15 days

[1] The Board will grant a stay if an informed decision on environmental issues (whether raised by a party or by the Board's Section of Environmental Analysis (SEA) in its independent investigation) cannot be made before the exemption's effective date. *See Exemption of Out-of-Service Rail Lines,* 5 I.C.C.2d 377 (1989). Any request for a stay should be filed as soon as possible so that the Board may take appropriate action before the exemption's effective date.

[2] Each OFA must be accompanied by the filing fee, which currently is set at $1,100. *See* 49 CFR 1002.2(f)(25).

[3] The Pierce County Parks and Recreation Department (Pierce County) filed a request for issuance of a notice of interim trail use for the entire line pursuant to section 8(d) of the National Trails System Act, 16 U.S.C. 1247(d). The Board will address Pierce County's trail use request, and any others that may be filed, in a subsequent decision.

after the EA becomes available to the public.

Environmental, historic preservation, public use, or trail use/rail banking conditions will be imposed, where appropriate, in a subsequent decision.

Pursuant to the provisions of 49 CFR 1152.29(e)(2), BNSF shall file a notice of consummation with the Board to signify that it has exercised the authority granted and fully abandoned the line. If consummation has not been effected by BNSF's filing of a notice of consummation by January 28, 2004, and there are no legal or regulatory barriers to consummation, the authority to abandon will automatically expire.

Board decisions and notices are available on our website at ''*www.stb.dot.gov.*''

Decided: January 15, 2003.

By the Board, David M. Konschnik, Director, Office of Proceedings.

Vernon A. Williams,

Secretary.

[FR Doc. 03–1611 Filed 1–27–03; 8:45 am]

BILLING CODE 4915–00–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 5498–ESA

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 5498–ESA, Coverdell ESA Contribution Information.

DATES: Written comments should be received on or before March 31, 2003 to be assured of consideration.

ADDRESSES: Direct all written comments to Glenn P. Kirkland, Internal Revenue Service, room 6411, 1111 Constitution Avenue NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to Carol Savage, (202) 622–3945, or through the Internet (*CAROL.A.SAVAGE@irs.gov.*), Internal Revenue Service, room 6407, 1111 Constitution Avenue NW., Washington, DC 20224.

SUPPLEMENTARY INFORMATION:

Title: Coverdell ESA Contribution Informaiton.

OMB Number: 1545–1815.

Form Number: 5498–ESA.

Abstract: Form 5498–ESA is used by trustees or issuers of Coverdell Education Savings accounts to report contributions and rollovers to these accounts to beneficiaries.

Current Actions: There are no changes being made to the form at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Business or other for-profit organization.

Estimated Number of Responses: 150,000.

Estimated Time Per Response: 7 minutes.

Estimated Total Annual Burden Hours: 18,000.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the 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 of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (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; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: January 21, 2003.

Glenn P. Kirkland,

IRS Reports Clearance Officer.

[FR Doc. 03–1793 Filed 1–27–03; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Revenue Procedure 2003–11

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Revenue Procedure 2003–11, Offshore Voluntary Compliance Initiative.

DATES: Written comments should be received on or before March 31, 2003 to be assured of consideration.

ADDRESSES: Direct all written comments to Glenn P. Kirkland, Internal Revenue Service, room 6411, 1111 Constitution Avenue NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the revenue procedure should be directed to Carol Savage, (202) 622–3945, Internal Revenue Service, room 5242, 1111 Constitution Avenue NW., Washington, DC 20224.

SUPPLEMENTARY INFORMATION:

Title: Offshore Voluntary Compliance Initiative.

OMB Number: 1545–1822.

Revenue Procedure Number: Revenue Procedure 2003–11.

Abstract: Revenue Procedure 2003–11 describes the Offshore Voluntary Compliance Initiative, which is directed at taxpayers that have under-reported their tax liability through financial arrangements outside the United States that rely on the use of credit, debit, or charge cards (offshore credit cards) or foreign banks, financial institutions, corporations, partnerships, trusts, or other entities (offshore financial arrangements). Taxpayers that participate in the initiative and provide the information and material that their

participation requires can avoid certain penalties.

Current Actions: There are no changes being made to the revenue procedure at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Business or other for-profit organizations, individuals, and not-for-profits institutions.

Estimated Number of Respondents: 2,000.

Estimated Average Time Per Respondent: 50 hours.

Estimated Total Annual Burden Hours: 100,000.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the 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 of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (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; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: January 21, 2003.

Glenn P. Kirkland,

IRS Reports Clearance Officer.

[FR Doc. 03–1794 Filed 1–27–03; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 8881

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 8881, Credit for Small Employer Pension Plan Startup Costs.

DATES: Written comments should be received on or before March 31, 2003 to be assured of consideration.

ADDRESSES: Direct all written comments to Glenn P. Kirkland, Internal Revenue Service, room 6411, 1111 Constitution Avenue NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to Carol Savage, (202) 622–3945, or through the Internet (*CAROL.A.SAVAGE@irs.gov.*), Internal Revenue Service, room 6407, 1111 Constitution Avenue NW., Washington, DC 20224.

SUPPLEMENTARY INFORMATION:

Title: Credit for Small Employer Pension Plan Startup Costs.

OMB Number: 1545–1810.

Form Number: 8881.

Abstract: Qualified small employers use Form 8881 to request a credit for start up costs related to eligible retirement plans. Form 8881 implements section 45E, which provides a credit based on costs incurred by an employer in establishing or administering an eligible employer plan or for the retirement-related education of employees with respect to the plan. The credit is 50% of the qualified costs for the tax year, up to a maximum credit of $500 for the first tax year and each of the two subsequent tax years.

Current Actions: There are no changes being made to the form at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Business or other for-profit organizations.

Estimated Number of Respondents: 100,000.

Estimated Time Per Respondent: 9 hours, 36 minutes.

Estimated Total Annual Burden Hours: 960,000.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number.

Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the 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 of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (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; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: January 21, 2003.

Glenn P, Kirkland,

IRS Reports Clearance Officer.

[FR Doc. 03–1795 Filed 1–27–03; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 8882

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and

other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 8882, Credit for Employer-Provided Child Care Facilities and Services.

DATES: Written comments should be received on or before March 31, 2003 to be assured of consideration.

ADDRESSES: Direct all written comments to Glenn P. Kirkland, Internal Revenue Service, room 6411, 1111 Constitution Avenue NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to Carol Savage, (202) 622–3945, or through the Internet (*CAROL.A.SAVAGE@irs.gov.*), Internal Revenue Service, room 6407, 1111 Constitution Avenue NW., Washington, DC 20224.

SUPPLEMENTARY INFORMATION:

Title: Credit for Employer-Provided Child Care Facilities and Services.

OMB Number: 1545–1809.

Form Number: 8882.

Abstract: Qualified employers use Form 8882 to request a credit for employer-provided child care facilities and services. Section 45F provides credit based on costs incurred by an employer in providing childcare facilities and resource and referral services. The credit is 25% of the qualified childcare expenditures plus 10% of the qualified childcare resource and referral expenditures for the tax year, up to a maximum credit of $150,000 per tax year.

Current Actions: There are no changes being made to the form at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Business or other for-profit organizations, and individuals.

Estimated Number of Respondents: 1,000,000.

Estimated Time Per Respondent: 9 hours, 41 minutes.

Estimated Total Annual Burden Hours: 9,680,000.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the 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 of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (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; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: January 21, 2003.

Glenn P. Kirkland,

IRS Reports Clearance Officer.

[FR Doc. 03–1796 Filed 1–27–03; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF VETERANS AFFAIRS

President's Task Force To Improve Health Care Delivery for Our Nation's Veterans; Notice of Meeting

The Department of Veterans Affairs (VA) gives notice under Public Law 92–463 that a meeting of the President's Task Force to Improve Health Care Delivery for Our Nation's Veterans is scheduled for Wednesday, February 12, 2003, beginning at 9 a.m. and adjourning at 5 p.m. The meeting will be held in the Horizon Ballroom of the Ronald Reagan Building International Trade Center, 1300 Pennsylvania Avenue, NW., Washington, DC, and is open to the public.

The purpose of the President's Task Force to Improve Health Care Delivery for Our Nation's Veterans is to:

(a) Identify ways to improve benefits and services for Department of Veterans Affairs (VA) beneficiaries and Department of Defense (DOD) military retirees who are also eligible for benefits from VA, through better coordination of the activities of the two departments;

(b) Identify opportunities to remove barriers that impede VA and DOD coordination, including budgeting processes, timely billing, cost accounting, information technology, and reimbursement; and

(c) Identify opportunities through partnership between VA and DOD, to maximize the use of resources and infrastructure, including buildings, information technology and data sharing systems, procurement of supplies, equipment, and services.

The morning and afternoon sessions will be a discussion of format and issues for the Final Report to the President.

Interested parties can provide written comments to Mr. Dan Amon, Communications Director, President's Task Force to Improve Health Care Delivery for Our Nation's Veterans, 1401 Wilson Boulevard, 4th Floor, Arlington, Virginia, 22209.

Dated: January 21, 2003.

By Direction of the Secretary.

Nora E. Egan,

Committee Management Officer.

[FR Doc. 03–1835 Filed 1–27–03; 8:45 am]

BILLING CODE 8320–01–M

Corrections

Federal Register

Vol. 68, No. 18

Tuesday, January 28, 2003

This section of the FEDERAL REGISTER contains editorial corrections of previously published Presidential, Rule, Proposed Rule, and Notice documents. These corrections are prepared by the Office of the Federal Register. Agency prepared corrections are issued as signed documents and appear in the appropriate document categories elsewhere in the issue.

FEDERAL ELECTION COMMISSION

Sunshine Act Notice

Correction

In notice document 03–1669 beginning on page 3253 in the issue of Thursday, January 23, 2003 make the following correction:

On page 3253, in the third column, in the second **STATUS** heading, ''closed'', should read, ''open''.

[FR Doc. C3–1669 Filed 1–27–03; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Notice of Intent to Rule on Application 03–05–C–00–RIC to, Impose and Use the Revenue From a Passenger Facility Charge (PFC) at Richmond International Airport, Richmond, VA

Correction

In notice document 02–32418 appearing on page 78562 in the issue of Tuesday, December 24, 2002 make the following correction:

On page 78562, in the second column, after the first full paragraph, under the section *Proposed charge expiration date:*, in the second line, ''2005'', should read, ''2025''.

[FR Doc. C2–32418 Filed 1–27–03; 8:45 am]

BILLING CODE 1505–01–D

Federal Register

Tuesday,
January 28, 2003

Part II

Department of Transportation

Research and Special Programs Administration

49 CFR Part 192

Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines); Proposed Rule

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket No. RSPA–00–7666; Notice 4]

RIN 2137–AD54

Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)

AGENCY: Office of Pipeline Safety (OPS), Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This document proposes to establish a rule to require operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could impact high consequence areas (HCAs). These integrity management programs would focus on requiring operators to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in high consequence areas. RSPA/OPS recently finalized the definition of high consequence areas by a separate rulemaking. This proposed rule proposes to expand the definition of HCAs by adding consideration of people living at distances greater than 660 feet from large diameter high pressure pipelines. The current HCA definition only requires consideration of people living at distances up to 660 feet from pipelines.

DATES: Interested persons are invited to submit written comments by March 31, 2003. Late-filed comments will be considered to the extent practicable.

ADDRESSES:

Filing Information

You may submit written comments by mail or delivery to the Dockets Facility, U.S. Department of Transportation, Room PL–401, 400 Seventh Street, SW., Washington, DC 20590–0001. It is open from 10 a.m. to 5 p.m., Monday through Friday, except Federal holidays. All written comments should identify the docket and notice numbers stated in the heading of this notice. Anyone desiring confirmation of mailed comments must include a self-addressed stamped postcard.

Electronic Access

You may also submit written comments to the docket electronically. To submit comments electronically, access the following Internet Web address: *http://dms.dot.gov.* Click on ''Help & Information'' for instructions on how to file a document electronically.

Privacy Act Information

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, *etc.*). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78) or you may visit *http://dms.dot.gov.*

General Information

You may contact the Dockets Facility by phone at (202) 366–9329, for copies of this proposed rule or other material in the docket. All materials in this docket may be accessed electronically at *http://dms.dot.gov/search.* Once you access this address, type in the last four digits of the docket number shown at the beginning of this notice (in this case 7666), and click on search. You will then be connected to all relevant information.

FOR FURTHER INFORMATION CONTACT: Mike Israni by phone at (202) 366–4571, by fax at (202) 366–4566, or by e-mail at *mike.israni@rspa.dot.gov,* regarding the subject matter of this proposed rule. General information about the RSPA/OPS programs may be obtained by accessing RSPA's Internet page at *http://RSPA.dot.gov.*

SUPPLEMENTARY INFORMATION: RSPA/OPS believes it can best assure pipeline integrity by requiring each operator to: (a) Implement a comprehensive integrity management program; (b) conduct a baseline assessment and periodic reassessments focused on identifying and characterizing applicable threats; (c) mitigate significant defects discovered in this process; and (d) monitor the effectiveness of their programs so appropriate modifications can be recognized and implemented. This approach also recognizes that improving integrity requires operators to gather and evaluate data on the performance trends resulting from their programs, and to make improvements and corrections based on this evaluation. This proposed rule does not apply to gas gathering or to gas distribution lines. This proposed rule will satisfy Congressional mandates for RSPA/OPS to prescribe standards that establish criteria for identifying each gas pipeline facility located in a high-density population area and to prescribe standards requiring the periodic inspection of pipelines located in these areas, including the circumstances under which an inspection can be conducted using an instrumented internal inspection device (smart pig) or an equally effective alternative inspection method. The proposed rule also incorporates the required elements for gas integrity management programs recently mandated in the Pipeline Safety Improvement Act of 2002, which was signed into law on December 17, 2002.

Background

RSPA/OPS is in the midst of promulgating a series of rules intended to require pipeline operators to develop integrity management programs for their entire systems, and to conduct baseline and periodic assessments of pipeline segments the failure of which could imperil the health and safety of nearby residents and cause significant damage to their property. These integrity management programs, written differently for the liquid and natural gas pipeline systems, are designed with the goal of identifying the best method(s) for maintaining the structural soundness (*i.e.,* integrity) of transmission pipelines operating across the United States. RSPA/OPS began this series of integrity management rulemakings by issuing requirements pertaining to hazardous liquid operators. A final rule applying to hazardous liquid operators with 500 or more miles of pipeline was published on December 1, 2000 (65 FR 75378). The hazardous liquid rule applies to pipeline segments that can affect high consequence areas (HCAs), which under the liquid rule criteria include populated areas defined by the Census Bureau as urbanized areas or places, unusually sensitive environmental areas, and commercially navigable waterways. RSPA/OPS issued a similar rule for hazardous liquid operators with less than 500 miles of pipeline (66 FR 2136; January 16, 2001).

Earlier this year, RSPA/OPS explained in the **Federal Register** that we were beginning the integrity management rulemakings for gas transmission lines by first proposing a definition of HCAs (67 FR 1108; January 9, 2002). We also described our plan to propose integrity management program requirements for gas transmission pipelines affecting those areas. In that proposed rule on HCAs (January 9, 2002), we also said we had decided first to propose the definition of HCAs and then to propose the gas integrity management rule. We chose to propose the regulation in two separate steps for a number of reasons. For example, operators already have good information

(through the Class Location Requirements) on where the potential consequences of a gas pipeline accident may be most significant. In addition, since we were still collecting information and verifying the validity of assessment methods other than internal inspection and pressure testing, presenting the gas pipeline integrity management requirements as a single rule would delay review of the HCA definition. RSPA/OPS recently finalized the definition of HCAs (67 FR 50824; August 6, 2002).

In the current definition of HCAs (August 6, 2002), we noted four significant characteristics of gas pipelines ruptures and explosions that are relevant in defining HCAs. These same characteristics are useful here in the context of developing integrity management regulations. Those characteristics are: (1) The effects of a gas pipeline rupture and subsequent explosion are highly localized. The physical properties of natural gas dictate that it rises upward from a rupture as the gas expands into the air; (2) The zone of damage or heat affected zone following a rupture is related to the line's diameter and the pressure at which the pipeline is operated; (3) The size of the heat affected zone from pipeline ruptures where pipe diameter was less than 36 inches and operating pressures were at or below 1000 psig, was limited to a diameter of 660 feet; and (4) The heat affected zone for pipelines of 36 inches or greater, operating at pressures in excess of 1000 psig, can extend 1000 feet. Based on these findings, the HCA definition included language that would require operators of large diameter pipelines operating at high pressures to include areas within a 1000 foot radius from the pipeline. This proposed rule, referred to as the gas integrity management program (IMP) rule, will expand the current definition of HCAs (August 6, 2002), by adding consideration of people living at distances greater than 660 feet from large diameter high pressure pipelines. This expansion is based on the need to provide the same level of added protection to population groups, as the current HCAs provide to facilities that house people who are difficult to evacuate, people with impaired mobility, people who are confined, and areas where people congregate. This population group living at distances greater than 660 feet was inadvertently omitted from the definition when we proposed and later finalized the HCA definition.

The HCA definition for gas transmission lines was based on broad corridors that could potentially be impacted from a pipeline rupture and explosion. However, additional calculations have to be used to determine the likely actual area that would be impacted. This proposed gas integrity management rule provides a method to analyze how a pipeline segment will impact an HCA if the segment fails. The definitions of a potential impact circle and potential impact zone that we are proposing, that are based on a mathematical equation, will essentially determine the likely actual area within an HCA that would be impacted. Whereas the HCA definition is based on broad corridors (*i.e.*, lateral distances perpendicular to pipeline) but not longitudinal distances (*i.e.*, axially along the pipeline), the potential impact circle and potential impact zones that we are proposing will provide longitudinal distances to define the actual area of impact in an HCA, and narrow the area to which the proposed assessment and repair requirements will apply.

This proposed rule also defines a Moderate Risk Area as an area located within a Class 3 or Class 4 location, but not within the potential impact zone. Whether a building located in a rural area, such as a rural church, which is currently included in the High Consequence Area definition, should be designated as a Moderate Risk Area requiring less frequent assessment or requiring enhanced preventive and mitigative measures is an issue for public comment that we discuss later in this document.

The process of identifying pipeline segments that are located in high consequence areas and moderate risk areas is described below under *Covered Segments.*

Pipeline Safety Improvement Act of 2002

On November 15, 2002, Congress passed H.R. 3609, the Pipeline Safety Improvement Act of 2002. The President signed the bill on December 17, 2002. Section 14 of H.R. 3609 contains requirements for integrity management programs for gas pipelines located in high consequence areas. The proposed rule which RSPA has been working on for some time is substantially in alinement with section 14 of H.R. 3609. However, there are differences. We have incorporated the requirements of section 14 into this proposed rule. These areas include the intervals for conducting baseline and reassessment testing, consideration of testing done prior to the final rule, the incorporation of issues raised by State and local authorities, the conduct of testing in an environmentally appropriate manner, a requirement that the operator notify RSPA of changes to its program, and a means to make copies of operator records available to State interstate agents.

Rule Synopsis

The elements of an integrity management program are to consist of: (i) An identification of covered pipeline segments and the potential impact zone for each segment; (ii) a baseline assessment plan; (iii) an identification of threats to each covered pipeline segment, including risk assessments of each covered segment; (iv) a direct assessment plan, if direct assessment is to be used; (v) provisions for remediating conditions found; (vi) a process for continual evaluation and assessment; (vii) preventive and mitigative measures; (viii) a performance plan as outlined in ASME/ANSI B31.8S, Section 9; (ix) recordkeeping requirements; (x) a management of change process as outlined in ASME/ANSI B31.8S, Section 11; (xi) a quality assurance process as outlined in ASME/ANSI B31.8S, Section 12; (xiii) a communication plan based on ASME/ANSI B31.8S, Section 10, to include a process for addressing safety concerns raised by OPS, including safety concerns OPS raises on behalf of a State authority with which OPS has an interstate agent agreement and of local authorities; (xiv) a process for providing, by electronic or other means, a copy of the operator's integrity management program to a State authority with which OPS has an interstate agent agreement; and (xv) a process for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

Covered Segments

Operators must identify covered segments prior to performing assessments. A covered segment is any transmission pipeline segment. The approach involves six steps that rely on the definitions contained in section 192.761. Those six steps are: (1) Identify all high consequence areas for the pipeline using the HCA definition as expanded by this proposed rule; (2) calculate the Potential Impact Radius (PIR) for each covered segment in the pipeline; (3) determine the Threshold Radius associated with the PIR for each segment; (4) identify Potential Impact Circles for the pipeline; (5) identify the Potential Impact Zones (PIZ) for the pipeline, and based on that zone for covered segments located in Class 3 and Class 4 locations, identify the moderate

risk areas; and (6) determine the priority of each covered pipeline segment (*i.e.*, segments subject to the proposed rule that are within a potential impact zone are considered higher impact zones; those segments outside a PIZ are considered lower impact zones). Additional detail on identifying covered segments is provided elsewhere in this preamble and in the Definitions located at section 192.761 of the proposed rule.

Assessment Methods

There are four acceptable assessment methods defined by this rule. They are: (a) Internal inspection (also know as in-line inspection, ILI and pig testing); (b) pressure testing; (c) direct assessment, (a process that includes data gathering, indirect examination and/or analysis, direct examination, and post assessment evaluation); and (d) any other method that can provide an equivalent understanding of the condition of line pipe. In addition, the rule proposes a method known as confirmatory direct assessment that an operator could use as an interim reassessment method.

The Pipeline Safety Improvement Act of 2002 provides for assessment by ''an alternative method that the Secretary determines would provide an equal or greater level of safety.'' Because the primary function of internal inspection tools or pressure testing is to determine the condition the pipe is in, we have determined that equivalent or greater safety can be provided by ''other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe.'' We used this language in the liquid integrity management program rules and are proposing to include it under the list of allowable assessment methods for the baseline assessment and reassessments.

The rule proposes to allow direct assessment as a supplemental assessment method on any covered pipeline segment and as a primary assessment method on a covered pipeline where in-line inspection and pressure testing are not possible or economically feasible or where the pipeline operates at a low stress. None of the permitted assessment methods listed above is fully capable of characterizing all potential threats to pipeline integrity. Currently, direct assessment is only an acceptable inspection method for assessing external corrosion, internal corrosion and stress corrosion cracking. In addition, if no other assessment method is feasible, direct assessment may be used to evaluate third party damage. Operators choosing direct assessment technologies must undertake extra excavations and direct examinations during the period while direct assessment is being validated.

Some additional details regarding direct assessment are highlighted here for the purpose of acquainting readers of this proposed rule with some of the basic principles associated with the use of direct assessment. First, for purposes of this rulemaking, above-ground inspection techniques (such as close interval surveys, direct current voltage gradient, and pipeline current mapper) are considered indirect examinations. Second, visual inspection, ultrasonic testing and x-ray examinations are considered direct examinations. Third, all three threats considered under direct assessment (external corrosion, internal corrosion, and stress corrosion cracking) are direct examination of pipe. Fourth, operators who assert that their pipelines cannot be internally inspected or pressure tested are required to include written justification in their plans explaining why their pipeline(s) cannot be tested using these methods. Fifth, operators who assert that internal inspection or pressure testing is not economically feasible will likewise be required to include written justification in their plans indicating why these methods are not economically feasible.

Another concept in the proposed rule is the use of Confirmatory Direct Assessment to evaluate a segment for the presence of corrosion and third party damage. This is a more streamlined assessment method that uses the steps involved in direct assessment to identify these significant threats to a pipeline's integrity. As discussed later in this document, RSPA/OPS is proposing that an operator use this method as an initial reassessment method within the required seven-year reassessment interval, if the operator has, within the proposed limits, established a longer reassessment interval for a particular segment. The follow up reassessment by pressure test, internal inspection or direct assessment would then be conducted at the established interval.

Additional information about direct assessment and confirmatory direct assessment is provided elsewhere in this preamble and at section 192.763(h) of the proposed rule.

Baseline Assessment Periods

Under this proposal, operators are required to complete a one-time baseline assessment on each covered segment. After a baseline assessment is completed on a segment, an operator will be required to reassess the covered pipeline segment at the specified interval. Operators using pressure testing or internal inspection as an assessment method are required to complete the baseline assessment of a segment located in an HCA within 10 years of December 17, 2002 (the date the Pipeline Safety Improvement Act was signed into law). 50% of the covered segments would have to be assessed within five years. Operators using pressure testing or internal inspection as an assessment method are permitted 13 years to assess pipeline segments located in Class 3 and 4 locations where the area being assessed is not within the potential impact zone *i.e.*, the areas we are proposing to define as moderate risk areas. (Additional detail on potential impact zones is provided in the Definitions section (§ 192.761) of this proposed rule and in the guidance that follows the proposed rule text.) If direct assessment is used as an assessment method, the proposal is for the operator to complete the baseline assessment within seven years for segments located in HCAs, with 50% of the segments having to be assessed within four years. Ten years would be allowed for a pipeline segment located in a Class 3 or 4 location where the segment being assessed is not within the potential impact zone *i.e,* is within a moderate risk area. Additional detail on baseline assessments is provided elsewhere in this preamble and at section 192.763(g) of the proposed rule. The timing of baseline assessments is covered in more detail at section 192.763(g)(4).

The Pipeline Safety Improvement Act of 2002 provides that a baseline assessment is to be completed ''not later than 10 years after the date of enactment * * *'' The Act further provides that at least 50% of covered facilities are to be assessed ''not later than 5 years after such date * * *'' Our proposal for baseline assessment using internal inspection, pressure test or equivalent technology is consistent with that requirement. We propose a shorter time frame for baseline assessment by direct assessment. The primary reason for proposing a shorter time frame is that direct assessment technologies are still under development and additional information needs to be gathered on their effectiveness. However, RSPA/OPS has been sponsoring research on direct assessment that should help expedite its validity as a method for assessment. Based on the results from this research OPS may be able to lengthen the time frame from five years to up to ten years.

Reassessment Intervals

The Pipeline Safety Improvement Act requires a minimum seven-year reassessment period. Thus, under the proposed rule we set a reassessment

interval of seven years for operators using pressure test, internal inspection or equivalent technology, and a five year interval for an operator using direct assessment that directly examines and remediates defects by sampling. However, an operator using pressure test, internal inspection or equivalent technology could establish a longer interval, within established limits if the operator by the seventh year conducts a reassessment using confirmatory direct assessment and then conducts the follow up reassessment by the chosen method in the year the operator has set for the interval. The interval for reassessment begins to run on a segment after the operator has completed the previous assessment for that segment.

Under the proposed rule, an operator establishes the reassessment interval for covered segments based on the type of assessment method the operator plans on using. The type of method used establishes the maximum interval. For operators using pressure testing, internal inspection, or alternative technology as an assessment method, the operator is to base the intervals on the identified threats for the segment or on the stress level of the pipeline and then refer to ASME/ANSI B31.8S, Section 8 to establish the interval. Under either option, the proposed maximum interval is ten years and 15 years for a pipeline operating at below 50% SMYS. However, because a reassessment must be conducted by the seventh year, under the proposal, if an operator establishes an interval of ten years for a segment, the operator would have to complete a confirmatory direct assessment by the seventh year, and then in the tenth year do a follow up reassessment using pressure test, internal inspection tool, direct assessment or alternative equivalent technology.

OPS has predicated the proposed 15-year maximum reassessment interval for pipelines operating below 50% SMYS on several factors.

• *Greater safety margin the current regulations provide.* Current pipeline safety requirements provide a greater safety margin against corrosion for gas pipelines located in populated areas. For example, the regulations require pipelines that are located in Class 3 and 4 locations (high population areas) to be of greater wall thickness than pipelines located in Classes 1 and 2 locations. And operators must replace the existing pipe with thicker, stronger pipe when population density increases (*i.e.*, the class location changes). Thus, pipelines located in populated areas are less susceptible to corrosion-induced rupture, because it takes much longer for corrosion to penetrate the pipe to a depth where the corrosion causes any concern.

• *The actual reassessment interval is based on risk factors.* The reassessment interval will depend on numerous risk factors, such as the baseline assessment results, the remediation of defects found during the baseline and the integration of data concerning other risk factors. Thus, higher risk pipe will be reassessed sooner.

• *Gas supply interruptions.* Gas transmission pipelines typically feed directly into customer distribution lines without an intermediate storage location. A pipeline's operating pressure is generally lower (*i.e.*, pipeline is at a lower stress level) when it is at the transition phase into a distribution line. This close coupling between the transmission and distribution systems increases the likelihood of a supply interruption if a single line is shutdown for assessment or repair. The 15-year maximum is intended to minimize these supply interruptions.

• *Industry consensus standards.* ASME B31.8S specifies a reassessment interval of 15 years for pipelines operating below 50% SMYS, and 20 years for pipelines operating between 20% and 30% SMYS. These reassessment intervals are based on a mathematical model Kiefner and Associates developed.

These factors led us to conclude that the proposed 15-year maximum reassessment interval for pipelines operating below 50% was reasonable for operators yet would ensure safety. Again, as discussed previously, an operator would have to complete a confirmatory direct assessment by the seventh year.

RSPA/OPS is inviting public comment on whether we should allow a maximum 20-year reassessment interval (with a confirmatory direct assessment in the seventh and 14th years) on pipelines operating at less than 30% SMYS, and reassessment by the confirmatory direct assessment method only every seven years for pipelines operating below 20% SMYS. The proposed confirmatory direct assessment method could be further streamlined for pipelines operating below 20% SMYS. OPS is considering a maximum interval of 20 years for pipelines operating between 20% to 30% SMYS (with a confirmatory direct assessment by the 7th and 14th years) because numerous studies and analyses have demonstrated that these low stress pipelines tend to leak, rather than to rupture. Current gas pipeline safety regulations recognize the reduced risk that low stress levels pose, and structure the requirements accordingly. Examples of different requirements for pipelines operating at lower stress are in § 192.65 (Transportation of pipe), § 192.227 (Qualification of welders), § 192.241 (Inspection and test of welds), § 192.309 (Repair of steel pipe), § 192.315 (Wrinkle bend in steel pipe), § 192.319 (installation of pipe in a ditch, § 192.505 (Strength requirements for steel pipeline to operate at a hoop stress of 30% or more of SMYS), § 192.711 (General requirements for repair procedures), and § 192.717 (Permanent field repair of leaks).

The maximum reassessment interval for operators using direct assessment as an assessment method is five years under this proposal, provided an operator directly examines and remediates defects by sampling. The reassessment interval under direct assessment would be expanded to ten years if an operator conducts a direct examination of all indications and remediates the anomalies. If an operator establishes an interval of more than seven years on a segment, the operator would have to conduct a confirmatory direct assessment by the seventh year. Additional detail on reassessment intervals is provided elsewhere in this preamble and at section 192.763(k) of the proposed rule.

RSPA/OPS is inviting public comment on whether we should allow an operator using direct assessment a maximum ten-year reassessment interval on a pipeline operating at less than 30% SMYS regardless of whether the operator excavates and remediates all anomalies on that line, or at least remediates the highest-risk anomalies. Again, the operator would have to conduct a confirmatory direct assessment by the seventh year of the interval.

The number of excavations (Dig Criteria) proposed for the direct assessment method follow those being developed by the National Association of Corrosion Engineers (NACE) Recommended Practices on Direct Assessment, with the following deviations:

(1) In each External Corrosion Direct Assessment (ECDA) region where all indications categorized as ''immediate'' are present, we propose that the operator reduce operating pressure by at least 20% until such indications have been excavated and mitigated.

(2) In each ECDA region where indications categorized as ''scheduled''are present, we propose the operator continue the excavations until at least two indications are excavated having corrosion of depth no greater than 20% of wall thickness.

(3) In each ECDA region, we propose to require one excavation; however, the excavation must be made at a location the operator considers most suspect, not at any random place.

RSPA/OPS is inviting public comment on whether the benefits of these proposed requirements that are more extensive than the NACE Recommended Practices currently being developed are worth the cost.

External Corrosion Direct Assessment and Internal Corrosion Direct Assessment

Work jointly funded by the gas pipeline industry and RSPA/OPS is ongoing to develop, validate and standardize the application of the direct assessment process to external corrosion (ECDA) and internal corrosion (ICDA). Future work is planned to develop, validate and standardize a direct assessment process for application to the stress corrosion cracking (SCCDA) threat. Furthermore, significant anecdotal evidence exists that the ECDA process may be capable of identifying coating damage associated with third party impacts on pipelines, but formal validation of this capability has not occurred.

ICDA is an assessment process that first identifies areas along the pipeline where water or other electrolytes introduced by an upset condition may reside, then focuses direct examination on the locations in each area where internal corrosion is most likely to exist. If no evidence of internal corrosion exists in these most likely locations, then the entire section can be considered to be free of internal corrosion. An operator using direct assessment as a method to address internal corrosion in a pipeline segment must follow the requirements in ASME/ANSI B31.8S, Appendix SP–B2, and in this section. Additional detail on ICDA is provided elsewhere in this preamble and at section 192.763(h)(3) of the proposed rule.

ECDA is an assessment process that combines assembly and analysis of risk factor data, indirect examination using above ground detection instruments, direct examination of suspected areas on the pipeline and post-assessment evaluation. The current approach being incorporated in the consensus standard under development for ECDA is to locate areas suspected of having external corrosion by identifying defects in the pipe coating, then excavating those defects in areas where corrosion activity is suspected. While all indications discovered by ECDA that are not adequately protected by the cathodic protection system at the time of the assessment will be excavated and directly examined, only a fraction of the ECDA indications that are protected by cathodic protection systems at the time of the assessment will be excavated. Additional detail is provided elsewhere in this preamble and at section 192.763(h)(4) of the proposed rule.

The Role of Consensus Standards

The underpinning analysis for this rulemaking was a consensus standard development effort. Completing this effort required nearly two years. This effort required assembling the best integrity assurance practices currently used by gas pipeline operators, and incorporating these practices into consensus standards. In addition the direct assessment process, which was conceived as a way to assess the integrity of gas pipelines for which in-line-inspection and pressure testing are not possible or economically feasible, needed to be developed, documented, and standardized. Some consensus standards on gas pipeline integrity management that we are considering incorporating by reference have been published. Others are still under development.

A major effort has been underway for several years to develop consensus standards supporting integrity management practices for gas pipelines. These standards are a necessary component in assuring the quality of implementation of any new assessment requirement. ASME/ANSI B31.8, Supplement, issued early this year, structures industry knowledge and best practices into requirements for an integrity management program and a set of prescriptive requirements for assessing pipeline integrity. In addition this standard describes the requirements an operator must follow to implement a performance-based program. The ASME/ANSI standard represents a significant advance in the documentation of demonstrated integrity management practices.

Although many of the tools employed in the direct assessment process have been in use for sometime, the use of these tools in the integrity assessment process is new. The National Association of Corrosion Engineers (NACE) undertook development of a Recommended Practices to support direct assessment and to expand the standardized application of In-Line Inspection (ILI).

RSPA/OPS is relying heavily on the technical content of these standards. RSPA/OPS has been directly involved in the development of these standards, both to ensure that the standards reflect the knowledge and perspective of RSPA/OPS, and to provide the basis for expanding requirements as needed within the Integrity Management Program (IMP) Rule. RSPA/OPS involvement included participation in the teams that developed the ASME/ANSI B31.8S standard, and ongoing participation in the development of the NACE Recommended Practice on Direct Assessment. In addition, RSPA/OPS supported participation by pipeline safety representatives from several States in the standards development and review process.

This proposed rulemaking is the culmination of experience gained from inspections, accident investigations and risk management and system integrity initiatives. This experience is the foundation for proposing a rulemaking that addresses, in a comprehensive manner, the National Transportation Safety Board's (NTSB) recommendations, Congressional mandates, including the mandates in the Pipeline Safety Improvement Act of 2002, and pipeline safety and environmental issues raised over the years. These issues and considerations include:

- Several NTSB recommendations concerning pipeline safety, including those which:

(1) Require periodic testing and inspection to identify corrosion and other time-dependent damage.

(2) Require the establishment of criteria to determine appropriate intervals for inspections and tests, including safe service intervals between pressure testing.

(3) Determine hazards to public safety from electric resistance welded (ERW) pipe and take appropriate regulatory action.

(4) Expedite requirements for installing automatic or remote-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipeline segments.

- Our analyses of several pipeline ruptures in Bellingham, Washington; Simpsonville, South Carolina; Reston, Virginia; and Edison, New Jersey, brought to light the need for operators to address the potential interrelationship among factors affecting failure causes and to implement coordinated risk control actions to supplement the protection provided by compliance with current regulations.
- Our analysis of the rupture in Carlsbad, New Mexico, highlighting the need for methods to assess internal corrosion in pipelines that are not piggable.
- Several Congressional mandates identify areas where the risk of a

pipeline failure could have significant impact. These specify that RSPA/OPS:

(1) Prescribe standards establishing criteria for identifying gas pipeline facilities located in high-density population areas (49 U.S.C. 60109(a)(2)).

(2) Prescribe, if necessary, additional standards requiring the periodic inspection of pipelines in high-density population areas, to include any circumstances when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect the pipeline (49 U.S.C. 60102(f)(2)).

(3) Survey and assess the effectiveness of Remote Control Valves (RCVs) to shut off the flow of natural gas in the event of a rupture of an interstate natural gas pipeline facility and make determination about whether the use of these valves is technically and economically feasible and would reduce risks associated with a rupture of an interstate natural gas pipeline facility. If the use of these valves determined to be technically and economically feasible and would reduce risks associated with a rupture of an interstate natural gas pipeline facility, then prescribe standards on the circumstances where an operator of a gas transmission pipeline facility must use an RCV (49 U.S.C. 60102(j)).

Risk Management and Systems Integrity Inspection Initiatives

This proposed rulemaking is also based on what we learned about integrity management programs from our risk management and pipeline inspection activities, particularly the Risk Management Demonstration Program, the Systems Integrity Inspection (SII) Pilot Program and the new high impact approach to inspections. These precursor activities began in 1997.

In the Risk Management Demonstration and Systems Integrity Inspection Pilot Programs, we studied and evaluated comprehensive and integrated approaches to safety and environmental protection. These approaches incorporated operator- and pipeline-specific information and data to identify, assess, and address pipeline risks, in conjunction with compliance with existing pipeline safety regulations. From these programs, we also expanded our knowledge of the extent and variety of internal inspection and other diagnostic tools that hazardous liquid pipeline operators use in their integrity management programs. We also learned of the wide variability in the extent and effectiveness of programs in use by operators to support management of pipeline integrity.

Additionally, based on risk management principles, RSPA/OPS implemented a systems approach through a new high impact inspection format that evaluates pipeline systems as a whole, rather than in small segments. The focus of the high impact inspection is on understanding how operators are addressing the issues that have been recognized as important through past inspections and incident history. High impact inspections are carried out periodically for each operator and the results are documented using heavier reliance on narrative description rather than on acceptability check marks. We found that a system-wide approach rooted in evaluation of operator response to incidents and recognized performance issues is a more effective and, in most cases, more efficient means of evaluating pipeline integrity. As part of this approach, we evaluate how pipeline operators integrate information about their pipelines to identify sources of risk and to determine the best means of addressing risk. This experience is helping us develop detailed inspection guidelines to evaluate compliance with the requirements of this rule.

RSPA/OPS continues to meet with representatives of the gas pipeline industry, research institutions, State pipeline safety agencies and public interest groups, to gather the information needed to propose an integrity management program (IMP) rulemaking pertaining to gas operators. Since January 2000, RSPA/OPS has attended several meetings with representatives of the Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), Battelle Memorial Institute, the Gas Technology Institute (GTI), Hartford Steam Boiler Inspection and Insurance Company, several gas pipeline operators and several representatives of State pipeline safety agencies. (*See* DOT Docket No. 7666 for summaries of the meetings.) We also have met separately with Western States Land Commissioners, National Governors Association, National League of Cities, National Council of State Legislators, Environmental Defense Fund, Public Interest Reform Group, and Working Group on Communities Right-To-Know.

On February 12–14, 2001, RSPA/OPS held a public meeting in Arlington, VA, on integrity management in high consequence areas for natural gas pipelines. At this meeting, reports on the status of industry and government activities on how to improve the integrity of gas pipelines were featured and meeting attendees participated in in-depth discussions on the integrity of gas pipelines. The reports can be found in the DOT docket (#7666) and the RSPA/OPS Web site under Initiatives/ Pipeline Integrity Management Program/ Gas Transmission Operators Rule.

At the public meeting, industry and State representatives presented their perspectives on a number of issues relating to integrity management.

Gas Advisory Committee Consideration

The Technical Pipeline Safety Standards Committee (TPSSC) is the Federal advisory committee charged with responsibility for advising on the technical feasibility, reasonableness, cost-effectiveness, and practicability of gas pipeline safety standards. The 15 member committee is comprised of individuals from industry, government, and the general public.

On February 7, 2001, RSPA/OPS briefed TPSSC members on gas integrity management program development. After canceling the September 13, 2001 meeting with TPSSC members, we sent all presentation materials and progress reports to committee members by mail for their comments or concerns. In May, 2002, we sent a document highlighting major issues in the gas integrity management rule to the TPSSC members. On July 18, 2002 the TPSSC met to review the Gas Transmission Pipeline HCA Rule and the cost-benefit analysis for the Gas Pipeline Integrity Management Program Rule. The committee voted unanimously to accept the cost benefit analysis as the basis for proceeding with the integrity management rule provided RSPA/OPS gives consideration to several issues. These issues and the related RSPA/OPS positions are summarized below.

The committee noted that the pipeline covered by the IMP Rule would include class 3 and 4 locations. RSPA's initial estimates of the total mileage in Class 3 and 4 locations turned out to be low because it was based on earlier data. Natural gas transmission pipeline operators were required to include in their 2001 annual reports the breakdown of their onshore pipeline mileage by class location, but this information was not available at the time the preliminary draft analysis discussed with the TPSSC was prepared.

RSPA/OPS has modified the cost benefit analysis to use the industry-reported mileage in classes 3 and 4. Because the industry regularly determines the classification of its lines, industry is in a better position than RSPA/OPS to estimate the amount of this mileage. RSPA/OPS is aware that there may be some discrepancy both between RSPA/OPS and operators and among operators as to how to calculate Class 3 locations. The variation in the manner in which class 3 locations are calculated involves the concept of clustering of buildings intended for

human occupancy in identifying pipe segments subject to the requirements associated with class 3 locations. The presence of individual isolated buildings within a sliding mile segment will count to raise the classification of the segment to Class 3. The question is whether the immediate area around the isolated building should be routinely classified as a Class 3 cluster. RSPA/OPS does not believe that these isolated buildings are commonly included as Class 3 clusters and does not intend this proposed rule to result in a change of existing practice in this regard.

The committee questioned whether RSPA/OPS intends to use the HCA definition as the starting point for identifying segments requiring additional integrity assurance measures, and to allow use of the potential impact zone to reduce the length of pipe subject to the IMP Rule. Committee members expressed concern both as to the appearance of leaving out some portions of HCAs and at the costs of including protections for areas which do not pose the same risks to population as other HCAs. With respect to the first point, the proposed rule includes all pipe segments within HCAs in the requirements for integrity management. However, if the segment is within a class 3 or class 4 location, but not within the potential impact zone, that is, the segment is in a moderate risk area, the proposed time for completing the baseline assessment will be extended to 13 years. RSPA/OPS expects that during the next seven to ten years, many companies will choose to make many segments in Class 3 locations piggable in their entirety and new technology will be available to minimize the cost associated with assessing these segments. However, an option RSPA/OPS is considering is to not require any assessment of segments located within a Moderate Risk Area, but, rather, to require enhanced preventive and mitigative measures on these segments. Our premise is that if houses are mostly clustered in one area of a Class 3 rectangle, a pipeline failure in an area beyond the cluster (*i.e.*, in the moderate risk area) may have little, if any, impact on the area with the cluster of homes. RSPA/OPS desires information on this option, and underlying assumptions, along with any cost information related to the proposed rule.

Committee members representing distribution companies expressed concern that they currently treat all their lines as Class 3 or 4 to avoid costly excavation and replacement of pipes when population densities increase. They are concerned that this decision will require them to perform segment identification for their lines. This would be an unnecessary cost if the distribution company intends to assess all transmission lines they operate. RSPA/OPS intends that operators choosing to classify their entire system as Class 3 or 4 without regard to population density will be allowed to do so without having to do segment identification according the provisions of the rule. However, these operators will not be relieved of requirements to evaluate the risk-based priority of segments in developing assessment schedules.

The committee expressed some concern that the approach being taken in the rule will lead to doubling protections on pipeline segments near population groups, since existing regulations already require lowering pipe stress levels in Class 3 and 4 locations. RSPA/OPS acknowledges this point, but notes that a significant consideration in our decision to allow a longer reassessment interval than that for liquid pipelines is that the thicker/stronger pipe in areas subject to the integrity management rule lengthens the time for time-dependent deterioration mechanisms to cause significant pipe deterioration.

Notice on Integrity Management Concepts and Hypotheses (Gas Transmission Pipelines)

On June 27, 2001, RSPA/OPS issued a notice of request for comments (66 FR 34318) that stated the objective in developing a rule on gas pipeline integrity management and described the scope and the elements of an eventual gas integrity management rule. We described seven elements that should be included in any integrity rule to fulfill our objectives. We used similar elements to those employed in structuring the liquid integrity management rules. Those seven elements were then elaborated upon through a set of hypotheses that we discussed in detail in the notice. The notice invited comment about these elements and hypotheses.

In addition, the notice summarized the areas where RSPA/OPS was seeking further information to support development of the proposed integrity management program rule for gas operators. The information needs were organized under the seven elements that we saw as essential to any integrity management program rule, and under two other categories where additional information was needed to evaluate the effect of an integrity management rulemaking on costs and gas supply, both seasonally and regionally.

Electronic Discussion Forum

RSPA/OPS also used an electronic discussion forum from June 27 through August 13, 2001, titled ''More Information Needed on Gas Integrity Management Program'' to help promote discussion of these issues. The electronic forum listed all the areas where we had asked for comment so that commenters could easily focus on those areas of interest to them. A transcript of the electronic discussion forum is included in the docket.

Comments to Notice on Integrity Management Concepts and Hypotheses (Gas Transmission Pipelines)

Comments to the docket were provided by one state, five industry associations (including one association of industrial gas consumers), sixteen companies or groups of companies that operate gas pipelines, one company that operates hazardous liquid pipelines, and one company that builds pipeline bridges.

Comments on all elements envisioned for the gas pipeline integrity management concept, except the element defining high consequence areas, are summarized below. Comments on the HCA element are discussed in a separate proposed rule published in the **Federal Register** on January 9, 2002 (67 FR 1108). RSPA/OPS recently finalized the definition of HCAs (67 FR 50824; August 6, 2002).

Scope

In the notice we indicated that we are considering applying the gas integrity management concept to all gas transmission lines and support equipment, including lines transporting petroleum gas, hydrogen, and other gas products covered under part 192.

The American Gas Association (AGA) and American Public Gas Association (APGA) commented that the integrity rule should apply to gas transmission pipelines operating at or above a hoop stress level of 20% SMYS. These commenters said the rule should also not include pipelines in commercially navigable waterways or environmentally sensitive areas because Congress did not direct this coverage. They also said RSPA/OPS should give special consideration to pipelines operating at a hoop stress between 20% and 30% SMYS. Because these lines fail by leak rather than by rupture, different assurance methods should be considered.

This proposed rule covers gas transmission pipelines, including pipelines transporting petroleum gas, hydrogen, and other gas products

covered under Part 192 in the high consequence areas. The definition for a transmission line is found in section § 192.3. This proposed rule does not apply to gas gathering lines or to gas distribution lines.

Performance-Based Option

Numerous companies argued that we should allow a performance-based option because a purely prescriptive rule would not allow companies to effectively and cost beneficially address the unique features of their systems.

We are proposing a minimum set of criteria for an operator to qualify for a performance-based option. Operators who satisfy this minimum set of criteria will be eligible to deviate from certain requirements—the time frame for remediating anomalies identified during the assessment, the conditions for using direct assessment as a primary assessment method and the reassessment interval (for example, the reassessment interval for on a segment assessed by the DA method could be extended to ten years). However, even if an extended interval were allowed, the operator would still have to conduct a confirmatory direct assessment in the seventh year of the interval. We are incorporating these performance-based considerations because RSPA/OPS recognizes that improving pipeline integrity can only be accomplished through operators improving their understanding of the condition of their piping and taking appropriate action based on this understanding. Operators who excel in these aspects of integrity management should have limited flexibility in making key integrity management decisions.

The proposed conditions an operator would have to satisfy before being allowed to deviate from some of the program's requirements include—

1. The operator must have completed a baseline assessment of all covered segments and at least one other assessment. Problems identified in the second assessment must be remediated. Also the results and insights from the second assessment must be incorporated into the operator's risk model.

2. An operator must also demonstrate that it has an exceptional integrity management program. To demonstrate this an operator must show that its program meets the performance-based requirements of ASME/ANSI B31.8S, has a history of measurable performance improvement, and includes, at minimum:

(1) A documented state-of-the-art risk analysis process;

(2) Complete documentation of all risk factor data used to support the program;

(3) A state-of-the-art data integration process;

(4) A process that explicitly develops lessons learned from assessment of covered pipe segments and applies these lessons to pipe segments not covered by the Rule;

(5) A process for evaluating all incidents, including their causes, within the operator's sector of the pipeline industry for implications both to the integrity of the operator's pipelines and to its integrity management program;

(6) A documented performance history that confirms the continuing performance improvement realized under the performance-based program; and

(7) The extensive set of performance measures documented in the operator's performance plan (ASME B31.8S, Section 9) are accessible to state and federal regulators. These measures would be updated by the operator on a frequency consistent with its performance plan.

Define the Areas of Potentially High Consequence

In the FR notice of June 27, 2001, we said the first element of the integrity management concept involves defining the areas where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and their property. In a rule issued on August 6, 2002, we defined these high consequence areas. (67 FR 50824). The definition of high consequence areas (HCAs) includes: (a) Current Class 3 and 4 Locations; (b) pipe segments in the area that would be impacted by a potential pipeline rupture where there is a facility housing people who are confined, have impaired mobility or are difficult to evacuate (*e.g.*, hospital, church, school, prison, day care facility, retirement facility; and (c) pipe segments near areas where a specified number of people congregate on a specified number of days per year (*e.g.*, camping grounds, outdoor recreational facility). The defined areas were those that would be impacted by a potential pipeline rupture, 300, 660 or 1000 feet from the pipeline depending on the diameter and operating pressure of the pipeline.

RSPA/OPS Decision on Using Potential Impact Radius in the HCAs

This proposed rule presents requirements to improve the integrity of pipelines located in areas of potentially high consequences. As discussed earlier, this proposed rule expands the current HCA definition, by presenting requirements to improve the integrity of pipelines located near people living at distances greater than 660 feet from large high pressure pipelines. This proposed expansion is based on the need to provide the same level of added protection to population groups, as the HCA definition provides to facilities that house people who are confined, difficult to evacuate, or of impaired mobility, and to areas where people congregate. The number of buildings intended for human occupancy within the potential impact circle is discussed under the proposed rule section of this preamble. The basis for identifying the physical area where concentrations of people are located so additional protective measures can be applied is discussed below.

The Size of the Zone That Could Be Impacted by a Gas Pipeline Rupture and Explosion

Since existing regulations provide a basic level of protection, the primary focus of the integrity management rulemaking is on reducing the likelihood of a gas release in areas where the potential consequences are greatest. The HCA definition includes areas where a pipeline lies within 660 feet of a building housing people who would be difficult to evacuate (*e.g.*, hospital, school, retirement facility) or where 20 or more people congregate at least 50 days in any 12-month period. The area is expanded to 1000 feet if the pipeline is greater than 30 inches in diameter and operates at pressures greater than 1000 psig. In addition, in this proposed rule we are expanding the HCA definition by proposing to include a new component of high concentration of buildings (as discussed above) intended for human occupancy beyond 660 feet. The 1000-foot limit was based on a mathematical model (developed by C–FER under INGAA funding) that describes a heat affected zone following a pipeline rupture. This heat affected zone is bounded by a ''potential impact radius.'' This model includes numerous assumptions on the size and orientation of the pipe rupture, the physical behavior of the jet issuing from a ruptured pipeline (the pipeline is assumed to fail by a double-ended rupture), the time of ignition of the gas jet, the rate of decay in the flow of gas issuing from the pipeline, the dominant heat transfer mode, and the criterion for determining the radius within which physical damage results from the heat from a burning gas jet. Given the complexity of this analysis and the scope of assumptions needed, the only

way to validate the adequacy of the resulting mathematical relationship was to compare its predictions of potential impact radius with actual observed burn zone following historic gas pipeline ruptures. This comparison was carried out using the C–FER model which successfully predicted the radius of the burn zone surrounding ruptured gas pipelines.

Incorporating Mathematical Formulation Describing the Heat Affected Zone Into the Rule

We are proposing to require operators to calculate the potential impact radius within the HCA. This potential impact radius would be used to identify the areas within HCAs where the consequences of a rupture would be greatest. An operator would first focus any additional integrity measures on concentrations of people or hard to evacuate buildings or areas where people congregate within the impact radius, then on the rest of the HCA. Using more realistic criteria to define areas where an operator would focus additional integrity assurance measures will allow an operator to better allocate its resources toward areas that need the greatest protection. This approach will particularly benefit operators of small-diameter, low pressure pipelines, where the range of impact following a potential rupture would be small. This approach would also benefit the public because operators of very large diameter, very high pressure pipelines would have an increased impact radius to consider for evaluating where additional integrity assurance measures are required.

Identify and Evaluate the Threats to Pipeline Integrity in Each Area of Potentially High Consequences

The second element of integrity management discussed in the FR notice of June 27, 2001, involves identification of potential threats to the pipeline. In the notice we mentioned one approach suggested by industry in our past discussions was to divide potential threats to pipeline integrity into three categories: Time dependent (including internal corrosion, external corrosion, and stress corrosion cracking); static or resident (including defects introduced during fabrication of the pipe or construction of the pipeline); and time-independent (including third party damage and outside force damage; this threat category was called ''random'' in the FR notice). These three categories are adopted here primarily to focus resource allocation decisions on useful strategies to improve integrity (*e.g.*, integrity management for the ''time-independent'' category clearly must incorporate significant preventive measures), but do not eliminate the need for operators to consider all major threats to pipeline integrity. In addition, we said that human error can influence any or all of these threats and therefore must be considered as a potential contributing factor to each threat.

For the gas pipeline IMP proposed rule, we decided to propose that the operator make a threat-by-threat analysis of the entire pipeline. Such an analysis will require identification and evaluation of the significance of threats to pipeline integrity, which must necessarily involve the integration of numerous risk factors. Such risk factors include, but are not limited to, pipe characteristics (*e.g.*, wall thickness, coating material and coating condition; pipe toughness; pipe strength; pipe fabrication technique; pipe elevation profile); internal and external environmental factors (*e.g.*, soil moisture content and acidity, gas operating temperature and moisture content); operating and leak history (*e.g.*, pipe failure history, past upset conditions that have introduced moisture into the gas); land use (*e.g.*, active farming, commercial construction, residential construction); protection history (*e.g.*, corrosion protection data, history of third party hits and near misses, effectiveness of local One Call systems); and the degree of certainty about the current condition of the pipeline (*e.g.*, age of the pipe, completeness of integrity-related records, available inspection data).

The RSPA/OPS data on causes of gas transmission pipeline accidents (*i.e.*, threats to the pipeline) show that between 1990 and1999, there were total 777 reported accidents. The causes of these accidents are broken down as follows:

—319 (41%) were due to outside force damage (30% third party, 11% earth quakes/floods, and other outside forces);
—173 (22%) were due to corrosion (105 (14%) internal, 67 (9%) external);
—119 (15%) were due to construction and material defects; and
—166 (21%) were due to other causes.

The data indicates that the two greatest threats to a pipeline are from outside force damage (41%), and corrosion (22%). Our data also shows there are more failures from internal corrosion than from external corrosion. The internal corrosion is caused by moisture and acidity present in the gas transmission lines at low or near low points. The rupture of the gas transmission pipeline in Carlsbad, New Mexico resulted from internal corrosion. Because corrosion can occur either internally or externally, it essential that gas pipeline operators consider both threats.

We believe this threat-by-threat analysis is necessary not only because it will require the operator to assemble and use a comprehensive set of risk factor data to identify the presence of potential threats, but also because it will support determination of the assessment approach or approaches needed to characterize the significance of these threats.

Our concept of integrity management also includes the following hypotheses: (1) Pipeline segments having threats that represent higher risks should generally be assessed sooner than those with threats that represent lower risk and (2) Pipelines that operate at a stress level less than 30% SMYS fail differently (*i.e.*, leak rather than rupture) from those operating at higher stress, therefore, different integrity assurance techniques may be appropriate. We have discussed this issue elsewhere in this document and have requested comment.

Comments on RSPA/OPS Hypotheses

INGAA provided many comments on this hypothesis. The primary source of information referenced by INGAA was the technical reports prepared by their contractors during the eighteen month interaction among INGAA, RSPA/OPS and the states on technical issues, and the consensus standards currently in preparation. These reports are available in the Docket. Comments from INGAA included the following:

INGAA offered the opinion that laws should be enacted to support strong One-Call Programs. It also pointed out that seam cracking in pre-1970 ERW piping has been observed only in piping from certain manufacturers. Not all pre-1970 pipe has that problem.

INGAA also expressed the opinion that soil erosion is not a significant direct threat to pipeline integrity, however it may lead to increased importance of third-party damage when it results in shallow cover. In addition, it noted that some materials and construction techniques are more susceptible to damage from massive soil movement than others, and that this issue is treated more completely in ASME B31.8 S which was under development at the time of the comment, but has subsequently been issued.

On the subject of operator error, INGAA noted that performance measures are needed to evaluate the importance of this threat to pipeline integrity. Lessons learned from observed operator errors should then be

translated into improvements in operating procedures and communicated among operators. Effective management of change and quality control/assurance programs will also reduce the likelihood of operator error contributing to pipeline failure. Consensus standards were under development at the time of the INGAA response on qualification and certification of individuals involved in analyzing in-line inspection (ILI) results. INGAA expressed concern about the increased demand for ILI services potentially leading to lengthened time requirements by ILI vendors to produce assessment reports, with related implications to the ability of the industry to meet repair and mitigation requirements.

On the subject of gas storage field pipeline systems, INGAA stated that those in high consequence areas should be treated in the same way as natural gas transmission pipelines.

AGA/APGA also noted that the process for managing pipeline integrity should not be affected by the operating stress level. Lower stress pipeline operators should be required to develop and follow integrity management programs having the same elements as operators of higher stress pipelines. Only the tools and techniques used to assess the pipeline and the reassessment intervals should require customization.

NYGAS indicated that it is important to ensure that staff conducting and analyzing results from assessment of pipeline integrity be qualified. In the cases where the operator qualification rule does not apply, operators must ensure proper qualification of these people, and monitor performance measures designed to reveal potential problems with personnel qualification. NISource commented that there needs to be a clear means of identifying a threat as ''significant.''

In aggregate these comments are consistent with the RSPA/OPS decisions to require threat-by-threat analysis of the pipelines and to acknowledge the differences in failure mode for pipe operating at stress levels below 30% SMYS by imposing somewhat different requirements for these lines.

Select Appropriate Assessment Technologies

The third element of integrity management discussed in the June 27, 2001 FR notice, involves identification of potential threats to the pipeline in areas of concern. In the notice we used the following hypotheses to support selection of the assessment technologies best suited to effectively determine the susceptibility to failure of each pipe segment that could affect an area of potentially high consequences:

- An integrity baseline needs to be established for all pipe segments that could affect an area of potentially high consequences. An operator will need to evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment and consequences of a failure on a high consequence area. Based on the type of threat or threats facing a pipeline segment, an operator will choose an appropriate assessment method or methods to assess (*i.e.*, inspect or test) each segment to determine potential problems.
- Time dependent threats will require periodic inspection to characterize changes in their significance.
- Acceptable technologies for assessing integrity include in-line inspection, pressure testing and direct assessment. None of these technologies, individually, is fully capable of characterizing all potential threats to pipeline integrity. (**Note:** RSPA/OPS is co-sponsoring with industry an evaluation of direct assessment technology to determine the conditions under which direct assessment is effective in assessing external corrosion. The effectiveness of direct assessment in assessing other threats (*e.g.*, internal corrosion, stress corrosion cracking) is also under evaluation for validation.
- Unless the operator demonstrates by evaluation that they are not a threat to the integrity of a pipe segment, static threats will require pressure testing at some time during the life of the pipeline. If significant cyclic stress, such as that caused by large pressure fluctuations, is present, then pressure testing, or an equivalent technology, will be required periodically throughout the life of the pipeline. If operating conditions for a pipeline with potential seam problems from manufacture are to be changed significantly, then the pipeline must by pressure tested prior to the change of operation.
- Time-independent threats will require the use of two parallel integrity management approaches. The vast majority (over 90%) of ruptures caused by time-independent threats occur at the time that the activity takes place (*e.g.*, when the excavator hits the pipeline), and not at some later time. Therefore, the use of risk management practices (or technologies) to prevent damage or to immediately identify the potential for damage would be more effective than looking for evidence of past damage. Secondly, since some time-independent threats do not result in immediate pipeline rupture, technologies that look for evidence of past damage after the threat has occurred should be focused in areas where delayed failure is most likely.
- Threats related to human error will be addressed largely, but not completely, through the new Operator Qualification Rule. The integrity management rule will require operators to evaluate the impact of operator error on the primary threats to pipeline integrity.

Comments

INGAA summarized the capability of pipeline in Classes 3 and 4 for using internal inspection tools as follows: 24.4% is easily piggable, 25.3% can be easily made piggable, 45.9% would be very costly to make piggable, and 4.4% cannot be pigged.

INGAA provided a set of examples of situations and conditions which may adversely impact the accuracy of results from the indirect processes used in external corrosion direct assessment. These include:

- Rocky backfill with little or no soil around the pipe.
- Very dry, cracked soil where little soil contact is made with the pipe.
- High-dielectric coatings (such as polyethylene tape) that have the propensity to shield the pipe from the flow of cathodic protection current, where no orifices to the soil/water interface are present.
- Resolution and sensitivity of survey equipment.
- Correct selection of the proper diagnostic tool matched to the suspected integrity threat.
- Bare or unprotected pipelines.

INGAA stated that data from the ongoing external corrosion direct assessment process development effort will need to be combined with data from application of the process over time to allow statistical analysis describing reasonable confidence bands.

A preliminary model was presented by INGAA that describes the use of the four step direct assessment process in assessing a pipeline for SCC. This description relies heavily on the assembly and integration of risk factor data that could indicate the possible presence of SCC. These risk factor data are presented in the appendix of ASME B31.8S.

AGA/APGA commented that not all pipelines should be required to be pressure tested for manufacturing or construction defects at sometime during their lifetime. For example, a pipeline should not require pressure testing if it has not experienced leaks during its lifetime. This argument assumes that

operation of the line is not subjected to pressure cycling of sufficient magnitude and frequency to produce growth of existing cracks. AGA/APGA does support existing requirements to pressure test all new pipelines before operation.

AGA/APGA commented that pipelines operating at hoop stress levels between 20% and 30% SMYS, where the failure mode is leakage not rupture, should be allowed to use assurance technologies, including mitigation measures, other than pigging, pressure testing and direct assessment. An AGA paper, dated April 26, 2001, on ''Integrity Management for Low Stress Pipelines'' (copy filed in the Docket) further expands on these alternate technologies and mitigation measures.

AGA/APGA indicated that direct assessment is: (a) Currently being validated and imbedded in a NACE consensus standard; (b) being evaluated for application to bare pipelines; and (c) should not be defined in an overly prescriptive manner.

AGA/APGA summarized the strengths and limitations of pressure testing and in-line inspection. They noted that all forms of integrity testing will have some impact on gas supply reliability, and that severe constraints or cut-off will be required with pressure testing.

The following table was developed by AGA/APGA on miles of member companies with various assessment capability.

Company membership	Miles in classes 3&4	Currently piggable (in percent)	Temp conversion for pigging (in percent)	Extensive retrofit for pigging [1] (in percent)	Cannot be pigged [2] (in percent)
AGA	13,500	12	10	43	35
APGA	3,000	13	.....	41	46

[1] Retrofit costs range from $5,000 to $250,000 per mile.
[2] Costs range estimated to be from $1M to $8M per mile to replace pipe (in urban areas).

The Florida Public Service Commission recommended that both magnetic flux leakage (MFL) pigging and pressure testing be carried out at intervals of five to seven years, not to exceed ten years. They also indicated that Florida gas pipes are typically less than twelve inches in diameter and therefore should be inspected at ten year intervals.

Pacific Gas & Electric Company (PG&E) also indicated that increased leak patrol frequency should be used to minimize the threat of leakage from pipe segments operating at low hoop stress (e.g., less than 30% SMYS).

PG&E commented that pipe segments operating at low stress levels should not be required to conduct a pressure test once in the pipeline life, but rather operating history should be used to validate material strength. They also noted they found direct assessment to be a good tool to identify residual third party damage.

PG&E noted that they do consider erosion to be one of the Outside Forces that needs to be considered, and they conduct annual erosion surveys to support mitigative action where erosion is identified.

PG&E summarized the reasons why some of its pipe is not piggable because of the presence of one or more of the following: telescopic construction, random diameter construction, sharp radius bends, and less than full opening valves.

NYGAS commented that local distribution company (LDC) transmission lines are typically sole source lines and are closely coupled to the distribution system. These facts will greatly increase the cost and impact on customer supply of pigging and pressure testing.

NYGAS further commented, with supporting analysis from Kiefner and Associates, that under typical cyclic loading conditions, the fatigue life of a gas pipeline operating at stresses of 72% SMYS is 100 to 400 times longer than hazardous liquid pipelines, and that lowering the operating stress level to below 30% SMYS will increase this factor to between 900 and 3600. Therefore, pressure testing at some time during the life of a low stress pipe should not be required. NYGAS also noted that experience has demonstrated ILI technologies do not perform satisfactorily at pressures below 400 psi.

NISource commented that it does not believe an integrity baseline needs to be established for all pipe segments. In particular, low stress pipelines have a ''baseline'' established through application of the exiting regulations and monitoring for evidence of leaks. Current practices identify the physical conditions which increase the potential for gas accumulation resulting from a leak, and the presence of these conditions leads to increased monitoring.

The Association of Texas Intrastate Natural Gas Pipelines commented that it would be useful if the rule spelled out the process by which new assessment technologies would be approved by RSPA/OPS.

Several operators expressed concern about their ability to de-water a pipe segment that is not piggable following a pressure test. Inability to de-water would lead to increased likelihood of internal corrosion. This fact supports the advisability of allowing direct assessment as an alternative assessment technology.

Comments from the public and the pipeline industry generally supported RSPA/OPS's approach in developing this proposed rule. The commenters generally agreed that the proposed rule should include: (1) A threat-by-threat analysis of each pipeline segment; (2) at least one pressure test during the life of a pipeline to characterize its susceptibility to material and construction defects, unless the operator can justify why a pressure test is not necessary; (3) periodic assessment of each pipeline segment for third party damage (denting), unless the operator can justify why such assessment is not necessary. A decision to forgo periodic assessment must address loading conditions (*e.g.*, cyclic loading), pipe susceptibility to delayed failure (*e.g.*, at Edison, NJ), and pipe exposure to potential third party damage; and (4) a description of how to apply direct assessment, including the conditions under which it is not appropriate, and conservative criteria for pipe excavation for direct examination.

Baseline Assessment and Remediation

The fourth element of integrity management discussed in the June 27, 2001 FR notice, related to the baseline assessment and remediation time frame. To determine time frames to conduct a baseline integrity assessment and to complete remediation following an assessment using an approach that prioritizes pipeline segments based on risk, we used the following hypotheses:

- The time frame for conducting the baseline assessment should be based on a graded or tiered approach where pipeline segments are prioritized for

assessment according to the level of risk they pose. Thus, highest risk segments would be scheduled for assessment first, lowest risk last. A schedule for taking remedial action on the pipeline segment after the assessment would also be based on risk factors.

• The time frame for conducting the baseline assessment should, among other factors, consider the impact on gas supply to residents. This could also be a factor in determining if a variance from the required time frame is warranted.

• The sequence in which the segments are prioritized for assessment should be determined by considering information such as, how much pipe is in areas of potentially high consequences, which of these pipe segments represent the highest risk, which threats for these segments represent significant risks, how much time will be needed to develop the infrastructure to perform the required assessments (*e.g.*, validate the required assessment technologies, develop consensus standards for the application of these technologies, expand the industry capability to deploy and effectively use these technologies to assess pipeline integrity). If the assessment finds potential problems, the schedule for making the repairs would also be based on risk factors.

Comments on Baseline Assessment and Remediation

INGAA commented that several practical factors will influence the time frame for completing a baseline assessment. These include time for: (a) Program development (suggested, 18 months); (b) assembly and analysis of risk factor data (suggested, 18 months); (c) limitations on the availability of assessment tools from vendors; and (d) potential detrimental impacts on supply to critical customers. Given these factors, INGAA estimated that the shortest time for completing baseline assessments would be about ten (10) years after promulgation of the rule. Even if ten years were allowed, INGAA estimated in an early analysis that the economic cost to customers over the ten year baseline assessment period would range from $3.9 to $6.1 billion.

INGAA reported that repair time frames should consider the results of a recently completed analysis by Kiefner and Associates in which the allowable repair time is related to the calculated (or pressure tested) safe operating pressure. Three categories were defined: (a) Segments with a safe operating pressure of 110% of MAOP or less should be repaired immediately, (b) those with a safe operating pressure of less than 139% of MAOP but above 110% of MAOP should be repaired on a defined schedule, and (c) those with a with a safe operating pressure of greater than 139% of MAOP require interval monitoring. Interval monitoring implies reassessment on a ten year interval to assure that sub-critical anomalies will not fail during that time.

AGA/APGA commented that factors considered in determining the time frame for the baseline assessment should include scope of the rule (*i.e.*, only above 20% SMYS), availability of pigging equipment, availability of properly qualified people, and the impact on the gas supply. Considering these factors, they believe that a minimum of ten (10) years should be allowed to complete the baseline assessment, with half of the pipeline completed within five years and variances available for those unable to meet the schedule.

AGA/APGA agree that repairs should be scheduled to reflect the seriousness of the defect. However, engineering distinctions among the gas pipeline systems dictate that the highly prescriptive approach to repair requirements in the Large Liquid Pipeline Operator Rule is inappropriate. RSPA/OPS should consider the guidance on repair and mitigation being developed by the ASME/ANSI B31.8S.

The Association of Texas Intrastate Natural Gas Pipelines commented that it would be useful if RSPA/OPS included a special provision for assessment interval for new pipe segments or replaced pipe segments.

PG&E supported a ten year baseline assessment period. PG&E commented that practical considerations (*e.g.*, long-lead materials, construction difficulties, and economies of scale) should be considered in developing assessment schedules to ensure that economic efficiencies can be realized while satisfying the intent of any rule that the highest risk segments be assessed first.

Enron commented that a ten year baseline assessment interval seems appropriate, and that reassessment in class 1 and 2 locations should be on the same interval, but that reassessment in Class 3 and 4 locations should be on a fifteen year interval. Enron also strongly urged RSPA/OPS to allow operators to carry out repairs consistently with existing procedures rather than imposing a prescriptive repair time frame.

Baseline assessment factors: The recent pipeline safety law (Pipeline Safety Improvement Act of 2002) requires that an operator conduct a baseline assessment not later than ten years from the date the law is enacted. This time frame is consistent with the baseline time frame we were considering based on our study of the relevant influencing factors. The law further requires that at least 50% of facilities in high consequence areas must be assessed no later than 5 years from enactment. This requirement is also consistent with what we were considering. Our proposal incorporates these requirements.

The factors we considered relevant to establishing the time frame for an operator to conduct the baseline assessment include:

• The desire to establish an integrity baseline for all affected pipe segments as quickly as possible.

• The ability of the gas pipeline service industry to expand both its assessment equipment, and, of equal importance, its qualified technical staff.

• The ability of the pipeline industry to gather and integrate risk factor data necessary to characterize the significance of threats to pipe integrity.

• The time required for the pipeline industry to modify its lines to accommodate in-line inspection equipment.

• The impact on critical gas supply and the associated impact on the price of natural gas. INGAA recently funded a study to evaluate the supply and consumer cost impacts associated with various baseline assessment intervals. The study did not include the actual cost of modifying the pipeline to accommodate ILI equipment, and the study assumed operators would perfectly coordinate their assessment activities to minimize the impact on customers. The study included supply impacts resulting from modifying a pipeline to accept ILI equipment and from the assessment activity itself. Supply impacts associated with remediation or repair of defects discovered during the assessment were not included. The study included differences in the supply impacts associated with different assessment technologies.

The INGAA analysis found that consumer cost impact was more significant with short baseline assessment periods than with longer times. The cost impacts in the current analysis were estimated to be $7.2B for a 14-year baseline period, $13.1B for a 10-year baseline period, and $20.1B for a 5-year baseline period. Although not quantifiable in the model, the potential for critical supply interruptions, resulting from the need to perform assessments during high demand periods and the increased difficulty of coordinating assessments on lines

feeding the same customers, increases as the baseline period decreases.

• *Class location requirements.* The gas pipeline safety regulations have class location requirements that the liquid regulations do not. As population increases near a pipeline, the class location requirements require establishment of an additional margin of safety. To comply with class location requirements, gas transmission pipeline operators maintain data on the number of residences and other buildings located near their pipelines. Based on threshold levels of near-by dwellings and buildings, operators are required to constrain the maximum stress level in the pipeline to successively lower levels as the number of dwellings increases. When a class location changes to a higher class, an operator must reduce the stress level on the line either by reducing pressure, or in some cases, by replacing the pipe. If an operator replaces the pipe, an operator may use thicker walled or higher strength pipe to ensure that the capacity of the pipeline is not reduced.

The result is that, while gas pipelines in locations of potentially high consequence typically operate at stress levels of 40% SMYS (Class 4) or 50% SMYS (Class 3), corresponding liquid pipelines typically operate at 72% SMYS. A higher stress is typically associated with thinner walled piping or a smaller margin to failure for a given defect size. Therefore, time dependent threats such as external corrosion, which occur at a rate dependent on factors such as soil chemistry, coating integrity and cathodic protection effectiveness, have less wall thickness to penetrate before a critical defect depth is reached and the pipeline ruptures. The lower stress levels and thicker walls of gas pipelines imply that, other factors being equal, corrosion would take longer to penetrate to a critical depth.

These factors support a baseline assessment interval of ten years for operators using in-line-assessment or pressure testing, with at least 50% of the covered segments (the higher risk segments) being assessed within five years. However, for operators using direct assessment as the primary assessment technology, we are proposing a baseline assessment interval of seven years to account for the early state of development of these processes and to allow time to develop data on their validity. The highest risk half of the segments being assessed by direct assessment will, however, be assessed during the first four of these seven years. This proposal is consistent with The Pipeline Safety Improvement Act of 2002 (HR 3609, signed into law Dec. 17, 2002) which provides for a baseline assessment ''not later than 10 years'' after the law's enactment, with 50 % having to be assessed ''not later than 5 years'' after enactment. As noted earlier, RSPA/OPS is proposing to require operators choosing direct assessment technologies to undertake extra excavations and direct examinations during the period while validation is continuing.

Our proposal on the baseline assessment also allows for an assessment conducted five years before the law's enactment or date the final rule is effective, whichever is earlier, as a baseline assessment if it satisfies the specified assessment criteria. If an operator chooses this option, under our proposal, the operator would then have to begin complying with the requirements for reassessment of the segment.

Identify and Implement Additional Preventive and Mitigative Measures

The fifth element of integrity management discussed in the June 27, 2001, FR notice, related to identification and implementation of additional preventive and mitigative measures. We used the following hypotheses in the notice:

• Assuring a pipeline's integrity requires more than simple periodic inspection of the pipe. Most threats, including passive threats such as third party damage, require active management to prevent challenges to integrity. Therefore, active integrity management practices are necessary. Some operators already go beyond the current pipeline safety regulations by implementing integrity management practices such as ground displacement surveys, soil corrosivity analysis, gas sampling and sampling and analysis of liquid removed from pipelines at low points.

• Preventive and mitigative measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety. Such actions may include, damage prevention practices, better monitoring of cathodic protection, establishing shorter inspection intervals, and installing Remote Control Valves (RCVs) or Automatic Shut-Off Valves (ASVs) on pipeline segments. Some operators, particularly hydrogen pipeline operators, have voluntarily installed ASVs on their pipelines closer together than required as a mitigative measure.

Comments

INGAA described a general process used by operators to make decisions on adding risk control or mitigation features beyond those required by regulation. The process involves establishment of a budget for additional safety enhancements and allocating that budget based on some structured form of risk assessment process, including feedback on potential risks from people in the field.

The conclusions of two INGAA-sponsored reports on the value of RCVs and ASVs include:

1. Neither RCVs nor ASVs will reduce fatalities or injuries to the public.
2. Neither control valve system will significantly reduce property damage.
3. RCVs and ASVs increase the likelihood of service disruption (RCVs in particular).
4. RCVs and ASVs can reduce the amount of product lost.
5. Costs for RCVs or ASVs outweigh measurable benefits.

According to INGAA, the only substantive benefit of RCVs and ASVs is that they result in faster valve closure following an incident.

Air Products and chemicals, an operator of 700 miles of pipeline for transporting industrial gas such as hydrogen, currently uses twenty-five excess flow valves along the 150 miles of pipe it operates in what it considers to be high consequence areas. These valves were added as a result of its risk analysis process.

GPTC noted that it expects ANSI to publish a technical report describing industry practices and ideas for managing integrity this Fall and requests that RSPA/OPS consider information in this document as part of its Rulemaking effort.

Remote Control Valves (RCVs)

In response to a Congressional mandate following the March 1994 gas transmission pipeline failure at Edison, NJ (Accountable Pipeline Safety and Partnership Act of 1996; codified at 49 U.S.C. 60102(j)), RSPA/OPS surveyed and assessed the effectiveness of remotely controlled valves (RCVs) on interstate natural gas pipelines. We examined the technical and economic feasibility of RCVs to rapidly shut down a gas transmission pipeline after a rupture.

RSPA/OPS conducted a public meeting in October 1997 to gather data on the technical and economic feasibility of installing RCVs. There was general agreement by the meeting participants, and in written comments following the meeting (contained in Docket No. RSPA–97–2879), that RCVs are technically feasible, but are not economically justifiable from a cost-benefit standpoint. This result is because most casualties and property

damage occur within ten minutes after a pipeline rupture. Although an RCV can be closed within two or three minutes to isolate a pipeline section, a safe condition is not achieved until the gas between valves has either escaped or burned off, which is almost always a longer time period than ten minutes.

These findings from the public meeting were reinforced by the results of a Gas Research Institute (GRI) study of 80 gas transmission pipeline failures over a twelve year period which showed that quick closure of valves could have prevented only one injury out of a total of 28 fatalities and 116 injuries.

We closely monitored a one year field evaluation of 90 RCVs installed by Texas Eastern Transmission Company, mostly in New Jersey and Pennsylvania. The RCVs' reliability was demonstrated by the fact that there were no unplanned closures of the valves during the year and, of the 200 plus valve cycles executed remotely, the valves closed 100 percent of the time on the first attempt.

RSPA/OPS completed a study in September 1999 titled ''Remotely Controlled Valves on Interstate Natural Gas Pipelines,'' available in Docket RSPA–97–2879. The study shows that installing and using RCVs can effectively limit the time required to isolate ruptured pipe sections when manual valve operation is not feasible, thereby minimizing the consequences of certain gas pipeline ruptures. The study supports RCVs' effectiveness, technical feasibility, and potential for reducing risk. The study indicates that the quantifiable costs of RCV installations would almost always exceed the benefits.

However, we believe that significant risk exists at some locations as long as gas is being supplied to a rupture site, and operators currently lack the ability to quickly close existing manual valves. Any fire would be of greater intensity, and would have greater potential for damaging surrounding infrastructure, if the fire were replenished with gas over a protracted period of time. Therefore, we held another public meeting in November 1999 to consider the need for a rulemaking to establish time limits for isolating ruptured sections of gas transmission pipelines. No new data were presented at the hearing to establish critical locations where RCVs should be installed.

Consistent with the hypotheses prepared earlier, RSPA/OPS decided to incorporate a provision in the rule requiring operators to evaluate the potential value of a spectrum of preventive and mitigative measures, and to act on the results of this evaluation. So that RSPA/OPS may understand the basis on which operator decisions are made, we will require operators to document their decision processes and decision criteria for RSPA/OPS review during inspections. Measures to be considered by operators will include those practices set forth in ASME B31.8S, as well as use of RCVs and ASVs. While these two types of valves have been analyzed generically for gas pipelines, RSPA/OPS believes that each operator should consider the merits of installing these mitigative measures at critical locations on their pipelines and make installation decisions based on pipeline-specific and site-specific evaluations.

A Process for Continual Evaluation and Assessment To Maintain a Pipeline's Integrity

The sixth element of integrity management discussed in the June 27, 2001 FR notice, related to the process for continual evaluation and assessment of pipelines to maintain their integrity. We used the following hypothesis in the notice:

Operators should continually evaluate and reassess at the specified interval each pipeline segment that could affect an area of potentially high consequence using a risk-based approach. The evaluation considers the information the operator has about the entire pipeline to determine what might be relevant to the pipeline segment.

- Managing a pipeline's integrity requires periodic reassessment of the pipeline. The time frame appropriate for this reassessment depends on numerous factors. In the current class location change regulation, gas pipeline operators are required to replace pipe segments with thicker-walled or stronger pipe (or to decrease pressure) as the near-by population increases above threshold levels. This requirement for thicker-walled or stronger pipe in areas of higher population might indicate that a longer reassessment interval would be appropriate where corrosion is the dominant threat.
- If critical risk factor data are not available to support evaluation of risks, then the reassessment interval should be appropriately shortened to reflect that absence of knowledge.
- If an operator has developed a comprehensive picture of past and anticipated threats, including detailed information on risk factors and records of multiple assessments carried out over several years, the operator might be able to justify a longer reassessment interval (see the discussion above on performance-based requirements).
- The periodic evaluation is based on an information analysis of the entire pipeline.

Comments

INGAA's comments included a discussion of the results of a Battelle analysis on assessment intervals. The analysis indicated that while the recommended reassessment interval in their report was developed based on the assumption that operators would use thicker pipe to address the Class Location requirements, the recommended interval would not be affected if operators chose to use higher strength pipe (rather than thicker pipe) to comply with changes in class location.

In addition, INGAA offered the opinion that the series of new integrity management regulations will lead to a situation in which the demand for assessment equipment and people qualified in its use and in interpretation of results will outpace the supply. This factor should be considered in determining the baseline and reassessment interval requirements.

INGAA recommended that RSPA/OPS solicit information from direct assessment service providers to evaluate the ability of the service providers to respond to the requirements for increased assessment included in the new IMP Rules.

AGA/APGA urged RSPA/OPS not to require reassessment on a prescribed interval. Intervals should be dictated by analysis using accepted risk principles along with results from the baseline assessment. If a prescriptive requirement on reassessment interval is needed, then RSPA/OPS should allow operators to deviate from that interval if it can justify such a deviation.

NYGAS commented that local distribution companies (LDCs) need greater flexibility in managing repairs and mitigative action than is implicit in the repair provisions of the liquid operator rule for operators with 500 or more miles of pipeline. The absence of such flexibility will lead to gas supply interruptions to customers.

RSPA believes that once the baseline assessment has been completed, the availability of qualified vendors and assessment equipment are no longer factors, since it is quite likely that the pipeline service industry will expand to meet the new higher level of demand. In addition, the major line modifications required to accommodate in-line inspection (ILI) equipment should be completed. Some of the factors influencing reassessment intervals are discussed above under baseline intervals. Other factors that influence

the periodic reassessment interval include:

- The stress level at which the pipeline operates;
- The growth rate of corrosion defects; and
- The repair criteria used in remediating defects discovered in previous assessments.

Figure 7–1 and Table 8–1 in ANSI/ASME B31.8S sumarize the relevant factors for determining a reassessment interval. The corrosion rates reflected in these charts represent the high end of historically observed corrosion, but are not the highest rates that might be experienced under special conditions, such as the presence of microbiologically influenced corrosion (MIC). Table 8–1 relates the recommended reassessment interval in years to the stress level of the pipe (% SMYS), the type of assessment carried out, and the significance of defects left in the pipeline following mitigation or repair. For a typical pipe segment in a Class 3 Location, the stress level would be 50% SMYS. At this stress, if a pressure test were carried out at 1.39 times the maximum allowable operating pressure (MAOP), then the recommended reassessment interval would be 10 years. This same recommended reassessment interval would result if ILI were used and all defects were repaired that had a predicted failure pressure below 1.39 times the MAOP. The recommendations for reassessment intervals following use of direct assessment are closely related to the details of the excavation criteria used in examining indications. The intervals shown in (Table 8–1 in ASME B31.8S) are based on technical analysis of time-dependent failure mechanisms (*e.g.*, external corrosion).

The recently-enacted pipeline safety law (HR 3609 signed into law Dec. 17, 2002) requires that reassessment be done at minimum intervals of seven-years. Thus, in our proposed rule, we have established a seven-year interval, but we also allow the operator to establish the intervals depending on the assessment method. Depending on the assessment method, the maximum interval an operator is allowed to establish could be longer than seven years. However, if the period is longer than seven years, the operator would have to conduct an interim reassessment by confirmatory direct assessment by the seventh year and then conduct the follow up reassessment in the year the operator has established. Thus, in the seven-year period an operator must either reassess a covered segment using the assessment method the operator has chosen, or if the operator has established a longer interval, conduct a confirmatory direct assessment by the seventh year with a follow up reassessment in the year the operator sets. Our proposal takes into account the factors we have discussed above.

Monitor the Effectiveness of Pipeline Integrity Management Efforts

The seventh element of integrity management discussed in the June 27, 2001 FR notice, related to monitoring the effectiveness of pipeline integrity management activities. We used the following hypothesis in the notice:

- Measures can be developed to track actual integrity performance as well as to determine the value of assessment and repair activities.
- Application of integrity management technologies that exceed current regulations is cost effective because many companies made the decision to implement such programs.

Comments

INGAA suggested that RSPA/OPS should consider including the following performance measures:

- Number of miles of pipeline inspected under IMP.
- *Repairs:*

1. Number of immediate repairs completed as a result of the IMP inspection program; and
2. Number of scheduled repairs completed as a result of the IMP inspection program.

- Number of leaks, failures and incidents (classified by cause).

AGA/APGA suggested that RSPA/OPS should work with stakeholders to develop performance measures immediately after promulgation of the integrity management rule. Additionally, in using these measures, RSPA/OPS must avoid inappropriate comparisons of performance among operators with vastly different systems.

NYGAS stated that performance measures should be properly used to monitor the effectiveness of integrity management efforts within individual companies, not to compare the performance among operators.

The Association of Texas Intrastate Natural Gas Pipelines commented that it would be useful for RSPA/OPS to establish performance measures that relate to each operator's integrity management plan, rather than requiring one-size-fits-all reporting requirements.

Enron commented that if RSPA/OPS were to increase the time for required submission of written pipeline incident reports by an additional sixty days, then there would be an opportunity to include better information on the evaluated cause of each incident.

The recently published standard ASME B31.8S discusses operator performance plans in Chapter 9. This discussion describes four measures that are required to be monitored by all operators using the standard. These measures are:

- Number of miles of pipeline inspected (assessed) versus program requirements;
- Number of immediate repairs completed as a result of the integrity management inspection program;
- Number of scheduled repairs completed as a result of the integrity management inspection program; and
- Number of leaks, failures and incidents (classified by cause).

RSPA/OPS is proposing to require operators to track and record these four overall performance measures, and make them electronically accessible (in real time) to RSPA/OPS for review. In addition, RSPA/OPS proposes to require operators to develop performance plans consistent with ASME B31.8S, and to define the extended set of measures that it will track. OPS will be able to review these measures during periodic field inspections. Appendix SP–A of ASME B31.8S tabulates suggested measures for each threat to which a pipeline might be subject.

Consideration of Impact on Gas Supply

The eighth consideration of integrity management discussed in the June 27, 2001 FR notice, related to the impact of the rule on gas supply. Performing an assessment test on gas transmission pipelines has the effect of restricting gas flow. Unless adequate time is allowed and the assessment process is carefully managed, this flow restriction can significantly impact gas supply and cost to customers.

Different assessment technologies have different restrictions on gas supply. In-line-inspection merely restricts flow for the relatively short time when the instrumented internal inspection device (pig) is in the pipe. However, preparing the pipe to make it able to be internally inspected (piggable), requires termination of the gas flow in the segment being tested while modifications are made. At present over 75% of gas transmission lines are not piggable or can be made piggable only with extensive modifications. Pressure testing requires termination of gas flow in the section being tested each time it is carried out. Direct assessment requires flow restriction (associated with lowering the pressure as a safety measure) while selected locations along the pipe are being excavated and directly examined.

We indicated above that assessing pipelines using any of the technologies under consideration may result in a restricted gas supply because of the need to take pipelines out of service or by reduction in throughput. In addition, some types of repairs will also require lines to be taken out of service. If an upstream segment of this gas transmission pipeline were put out of service temporarily for test or repair, many communities located at the end of branch lines, could be negatively impacted by the restricted gas supply. This effect would be caused by the fact that the lines are often sole source feed, (*i.e.*, have no other tie-in's from an alternative source.) Because of this factor, the proposed rule allows a waiver of a reassessment interval greater than seven years, if the operator demonstrates that it cannot maintain local product supply, and OPS determines that a waiver would not be inconsistent with pipeline safety. This proposal is consistent with the provision in the Pipeline Safety Improvement Act of 2002. Because a waiver requires public notice and comment, we are proposing 180-day advance notification.

INGAA Report

INGAA commissioned an extensive analysis of the economic impact of a gas IMP rule. The analysis, performed by Energy & Environment Analysis, Inc., evaluated this impact using various assumptions on the fraction of the affected pipe that is currently not piggable that will be assessed by pigging, pressure testing, or direct assessment. The time frame during which the baseline assessment must be performed was also a parameter in the analysis, varying from five to fifteen years. While (at the time of the INGAA comment—August 14, 2001) sufficient detail was not available to evaluate the credibility of the analysis and its underlying assumptions, the estimated economic impact on gas consumers for the ten year baseline period is large, ranging from $3.9 billion to $6.1 billion. (Note, this analysis and a peer review of report performed by the Volpe National Transportation Systems Center (Volpe Center) and the Department of Energy (DOE) have recently been completed and are discussed below).

AGA/APGA commented that some forms of assessment (*e.g.*, pressure testing) would require outages from 3 to 9 days. Customers would in some cases be without gas during that time, and restoration of gas supply would require extensive work, for example, re-lighting pilot lights of each affected customer.

Discussions on the INGAA Report on ''Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas'' (February 2, 2002)

On April 3, 2002, RSPA/OPS held a meeting with INGAA, Energy and Environment Associates (EEA), the Volpe Center, and DOE to discuss the INGAA report on ''Consumer Effects of the Anticipated Integrity Rule for High Consequence Areas'' (February 2, 2002). The meeting was designed to allow RSPA/OPS, and several reviewers retained by RSPA/OPS, to explore the reasonableness of the results in the INGAA-sponsored report. The focus of discussion was on the assumptions made in the analysis. The report was produced in response to the initial need to understand the supply and economic implications of allowing or disallowing direct assessment as a primary assessment technology, and later was expanded to evaluate the supply and economic implications of various baseline assessment intervals ranging from 5 to 15 years.

The report focuses on interstate transmission pipelines. INGAA indicated the industry expects that most HCA mileage will lie in Class 3 and 4 Locations, and that approximately 5% of pipeline is in class 3 and 4 locations, but that the HCA definition will include some pipe segments in other locations as well. INGAA said that Class 3 and 4 Locations are scattered throughout the pipeline system so they appear in about 60% of valve stations and 80% of the discharges from compressor locations.

INGAA further stated that a periodic inspection program was useful only to identify the presence of dynamic failure mechanisms or threats (*i.e.*, corrosion). They questioned the value of periodic assessment of pipelines for static threats (*i.e.*, material and construction) or random threats (*e.g.*, third-party damage).

The reviewers at the meeting requested clarification of the study assumption regarding the fraction of lines that are assumed to be in-line-inspected. Scenarios 1, 2 and 3 in the report assume segments described as ''currently piggable'' and ''relatively easy to make piggable'' are treated as ''easy to pig'' (*i.e.*, about 50%). The other scenarios, 3A, 3B and 3C in the report assume that only ''currently piggable'' segments are treated as ''easy to pig'' (*i.e.*, about 25%). This difference in assumptions complicates comparison between Scenarios 1, 2 & 3 and Scenarios 3A, 3B & 3C. EEA stated that market evaluations do show that there are capacity choke points and that spot market prices respond to capacity restrictions. Examples include recent price spikes in the States of California and New York. These capacity restriction effects were the focus of the study. No account was taken of the cost incurred by operators making lines piggable, although the capacity impacts associated with these maintenance activities were considered.

Other key assumptions in the analysis include: (1) 80% of mainline pipe and 50% of laterals/connections will be inspected (these numbers are supported by consideration of the distribution of segments that can affect HCAs throughout the pipeline systems and by the fact that even operators using direct assessment as their primary assessment approach will be required to reduce pressure in long segments of their lines during the direct examination step of the process). (2) Effects on consumers with limited options and flexibility in gas providers will be much more severe (*e.g.*, Florida has one transmission line, with a second to come in service this summer. Load factor on the line is greater than 80% and any interruptions would have significant downstream effect, and therefore cost impacts). It was noted by INGAA at the meeting that gas supply interruptions are not as routinely buffered by storage capacity as liquid petroleum products, which are normally stored in tanks. (3) The industrial sector is more elastic than the residential sector. Demand there was adjusted significantly when gas prices were high over the last couple years. (4) The analysis assumes that the impact of supply restrictions occurs at the time the restriction occurs rather than at a later time, as would occur because of long-term supply contracts. (5) Both pipeline capacity and demand are assumed to increase, as described in the base case of ''The Pipeline and Storage Infrastructure for a 30 Trillion Cubic Feet (TCF) Market'' better known as the ''30 TCF study.''

The TCF study uses the EEA Gas Market Data and Forecasting System. This model was developed in 1995 requiring over ten person years of effort. The model is rigorously calibrated to actual historical behavior. Price differences are calculated as a function of load factor. The calibration is updated annually.

The model is a fairly coarse one in which multiple supply lines between market centers are modeled as a single line. However, the model appropriately considers the effects of capacity restrictions in one line in a corridor, and does not assume that a single line out of service terminates supply through the corridor in which it resides. This effect is treated separately from the model and

provided as an input to the model. The inputs to the model are developed assuming perfect communication among operators with lines in a single corridor, or supplying a single market center such that operators do not take multiple lines out of service that would compound the impact on capacity restriction at that market center. Taking multiple lines out of service in a single corridor might be necessary, if the baseline assessment interval were sufficiently short to require such action.

As the market becomes thinner (*i.e.*, supply is restricted relative to demand at a market center) consumers bid against each other causing spot market prices to rise. Costs developed in the model may be overstated over a 10-year period, because all consumers do not pay spot prices. As pipelines are re-contracted, however, those costs will be reflected in the new contracts.

In response to questions about why pipe assessments carried out prior to the rule currently being considered have not strongly affected gas prices, INGAA indicated that people who currently administer active pigging programs represent only about 25% of the total pipeline mileage and implemented their programs over about a 20 year period. INGAA said that in response to the anticipated rule, operators would have to assess a significant fraction of their systems (the segments covered by a rule) over ten years. The associated supply impacts and consumer costs will therefore be much larger.

The reviewers at the meeting suggested it would be very useful if INGAA would summarize all major assumptions and discuss the direction and approximate magnitude (*e.g.*, small medium, large) of the effect of each assumption on the resultant cost impact. INGAA agreed to consider how best to respond to comments raised during the meeting and in the review documents that had been prepared in advance by Volpe and DOE reviewers. For detailed discussion on this subject see minutes of this meeting in the docket.

Other Issues Including Those Related to Cost/Benefit

The ninth consideration of integrity management discussed in the June 27, 2001 FR notice, related to other issues including those related to the cost/benefit analysis.

Comments

INGAA commented that RSPA/OPS should perform its cost-benefit analysis starting with current industry practices (as described in recent INGAA reports) as the baseline. They also provided some data on the number of incidents and property damage over the past fifteen years, but did not provide any information on the impact of incidents and leaks on the cost of gas to customers.

INGAA provided preliminary information on the estimated costs of inspection of all transmission pipelines for three different scenarios on inspection of hard-to-pig (HTP) pipelines. These preliminary costs include estimates to convert HTP segments to make them piggable. The inspections were assumed to be carried out over a ten year period.

Scenario description	Consumer cost for 10 years period (millions)
½ HTP portion pigged, ½ HTP portion DA	$3,892
½ HTP portion pigged, ½ HTP portion Hydro	6,095
⅓ HTP portion pigged, ⅓ HTP portion DA, ⅓ HTP portion DA	4,048

The numbers in this table were updated through the completed INGAA/EEA analysis discussed above.

On the question of small business impacts, INGAA noted that no more than 50,000 miles of approximately 274,000 miles of natural gas transmission pipelines (and probably much less) could be owned by small businesses. Also, many of the contractors likely to be involved in inspections are small businesses. Finally, the potential exists that increased gas costs will impact small business customers.

AGA/APGA strongly suggested that RSPA/OPS develop the integrity rule for gas transmission pipelines around a performance-based approach.

The Florida Public Service Commission noted that performance type regulations can only work if operators are willing to share information on both performance and potential problems with the regulators. They believe that the risk management demonstration program has shown the operators are unwilling to openly share needed information.

The New York Gas Group strongly supports the development of a performance-based rule that will allow companies the flexibility needed to manage the risks associated with their pipelines, as effectively as possible. They asserted that this position is supported by the NY State Public Service Commission staff.

The Process Gas Consumers Group (PGC) commented that RSPA/OPS should give strong consideration to any potential economic impact of interruptions in gas supply to industrial concerns that rely on gas in the conduct of their business.

Conclusions From the Consumer Cost Impact Evaluation

Consumer cost and supply availability are major factors in establishing the period for operators to complete the baseline assessment. There are numerous assumptions made in the INGAA study. In general they are designed to underestimate the predicted cost impact. For example, the study does try to optimize time of testing, and assume infinite availability of pig vendors and equipment. However, there are also assumptions in the study that would lead to prediction of higher cost impact than might realistically be expected. For example, the study does not assume learning on the part of the operators, and the analysis reflects marginal costs rather than contracted costs.

The EEA analysis found that consumer cost impact was more significant with short baseline assessment periods than with longer times. The cost impacts were estimated to be $7.2 billion for a 14-year baseline period, $13.1 billion for a 10-year baseline period, and $20.1 billion for a 5-year baseline period. Although not quantifiable in the model, the potential for critical supply interruptions, resulting from the need to perform assessments during high demand periods and the increased difficulty of coordinating assessments on lines feeding the same customers, increases as the baseline period decreases.

RSPA's Conclusions About the INGAA Study

From its review of the INGAA study RSPA concluded that—

Study Performers. The organization that performed the study for INGAA is recognized as an expert in the type of analysis performed. This conclusion is supported by the fact that EEA has been called to testify on significant supply issues before Congress, and that the gas pipeline industry is using the results of the study on which the present impact analysis is based as a major factor in expansion decisions.

Study Conservatism. The peer review identified several assumptions used in the analysis in which it would lead to over-prediction of the gas supply and cost impacts, as well as some areas where the model would be expected to result in under-estimation of these impacts. In balance, the model together with its major assumptions seems to produce a reasonable, possibly an

underestimate, of the anticipated supply and cost impacts.

Baseline Assessment Time Frame. The decision on a baseline assessment interval must reflect the need to expedite pipeline assessment without dramatically impacting gas availability and price. The INGAA/EEA analysis supports the conclusion that a ten-year baseline assessment requirement is consistent with managing supply and cost impacts resulting from the new assessment requirements. The predicted impact on consumer energy cost associated with this baseline time frame is $13.1 billion. While this is a very large cost, it represents a small percentage impact on total gas costs over the time period of the analysis. RSPA has concluded that a ten-year baseline assessment period, with 50% of covered segments being assessed within five years, will allow the impact on gas supply and cost to be adequately managed by the operators.

Mapping

We stated in the proposed rule on high consequence areas (67 FR 1108; January 9, 2002), that RSPA/OPS is creating the National Pipeline Mapping System (NPMS), a database that contains the locations and selected attributes of natural gas transmission lines and hazardous liquid trunk lines and liquified natural gas facilities operating in the United States.

RSPA/OPS will require operators to provide their pipeline data by a separate rulemaking on mapping. Submission of this information has been voluntary in the past. At present, RSPA/OPS has received data on pipe locations for 90% of liquid pipelines but only 52% of gas pipelines. Currently, RSPA/OPS has no data on areas of higher population density (Class 3 and 4 locations) associated with gas pipelines. Present gas pipeline regulations are structured to provide increasing levels of protections, consistent with predetermined thresholds. Accordingly, gas pipeline operators are required to monitor data on the number of dwellings within 660 feet of their pipelines to either lower operating pressure or to replace the pipe with one having greater wall thickness or strength as the number of dwellings increases above predefined threshold. RSPA/OPS therefore believes that operators have excellent data on population and places where people congregate near their pipelines.

Maps incorporating these data would be useful not only to pipeline operators, but also to federal and state inspectors and for local officials and community needs. RSPA/OPS intends to use operator-supplied information to map the high consequence areas that it defines in a gas integrity management rule, similar to how it is mapping these areas for the liquid operators. A separate rulemaking on mapping will address this issue.

Treatment of Storage Fields

Storage fields have provided a source of pipeline integrity problems for decades. RSPA/OPS asked for information to help identify the cause of and prevent piping-related failures associated with storage fields that could affect high consequence areas. INGAA stated that those in high consequence areas should be treated in the same way as natural gas transmission pipelines.

The proposed rule requirements will include pipelines within the storage fields because under § 192.3(c) such pipelines are defined as transmission lines.

The Proposed Rule

RSPA/OPS is proposing a modification to section 192.761 and addition of a new section 192.763 to subpart M: High Consequences Area Definitions and Integrity Management Programs. The § 192.761 titled ''Definitions'' defined ''high consequence areas'' in a recently issued final rule (67 FR 50824; August 6, 2002); and proposed a new section 192.763 ''Pipeline Integrity Management in High Consequence Areas'' is described in this rule.

High Consequence Area Definitions—§ 192.761

The definition of high consequence areas recently published in the **Federal Register** (67 FR 50824; August 6, 2002) includes: (a) Current Class 3 locations; (b) current Class 4 locations; (c) an area that extends 300 feet from the centerline of the pipeline to the identified site for a pipeline not more than 12 inches in diameter and having a maximum operating pressure lower than 1200 psig; (d) an area of 1000 feet from the centerline of the pipeline to the identified site for a pipeline greater than 30 inches in diameter operating at a pressure greater than 1000 psig; (e) an area that extends 660 feet from the centerline of the pipeline to the identified site for all other pipelines. The areas of 300, 660 and 1000 feet are corridors that have been determined based on generalized estimates of potential rupture consequences. An identified site is defined as a building or outside area that can be identified by one of several means and that houses people who are difficult to evacuate or have impaired mobility (*e.g.*, hospital, church, school, prisons, day care facility); or where there is evidence that 20 or more people congregate at least 50 days in a year (*e.g.* beach, camping ground, religious facility). The full text of the HCA definition can be reviewed in the **Federal Register** document referenced above.

An identified site can be identified by one of several means listed in the rule: it is visibly marked, it is licensed or registered, it is on a list or map maintained by or available from a Federal, State or local agency or a publicly or commercially available database or it is know by public officials. RSPA/OPS is inviting comment on whether we should use the term public safety officials (*e.g.* Police, Fire department) and/or emergency response officials instead of public officials. Currently, pipeline operators are required to conduct liaison activities with public safety officials or emergency safety officials. We would like comment on whether the term ''public safety officials or emergency response official'' will cover the persons having the relevant information about these identified sites.

On September 5, 2002, the American Gas Association (AGA), the American Public Gas Association (APGA), the Interstate Natural Gas Association of America (INGAA), and the New York Gas Group (NYGAS) filed a petition for the reconsideration of the final rule on the definition of HCAs for gas transmission pipelines (67 FR 50835; August 8, 2002). This petition is in the docket. The petition raised the following issues.

(1) The splitting of the gas integrity rule into two rulemakings—the definition and the integrity requirements—causes confusion, particularly, since the Potential Impact Zone concept was not included in the definition.

(2) The HCA definition should clarify that it applies to those gas transmission pipelines that have the potential to impact high population density areas and does not apply to distribution pipelines.

(3) The identified site component (buildings and outside areas) is overly broad. The definition should instead use the language in 192.5.

RSPA/OPS believes issuance of this proposed rule will alleviate most of the concerns raised in the petition. As previously discussed, the HCA rule only defines general areas of high consequence. It includes corridors (lateral distances of 300, 660, and 1000 feet), but not axial distances along the pipeline. The axial distances can only be determined by analysis of potential

impact zones which are covered in this proposed rule. We have put the proposed potential impact zones definition under the same section 192.761, where HCAs are defined.

The petitioners argued it would be difficult to identify a building or outside area that is frequented by 20 or more persons on at least 50 days in any 12-month period, and would include isolated and infrequently occupied buildings. RSPA/OPS does not know how many rural buildings would be covered by the HCA definition or how many miles of pipeline segments would have to be added to the assessment plans to include these buildings which are populated for a short time relative to the other populated areas. We are trying to focus on high risk areas for assessment. Instead of including rural buildings, such as rural churches as High Consequence Areas, we could designate them as Moderate Risk Areas requiring less frequent assessment or requiring enhanced preventive and mitigative measures only. We would like public comment on this issue. We are proposing to define a Moderate Risk Area as an area located within a Class 3 or Class 4 location, but not within the potential impact zone.

This proposed rule presents requirements to improve the integrity of pipelines located in areas of potentially high consequences that go beyond those HCAs. The proposed IMP rule proposes to expand the definition of HCA by adding consideration of people living at distances greater than 660 feet from large diameter high pressure pipelines. Populated areas at distances less than 660 feet are already accounted for under Class 3 and 4 locations, however, populated areas beyond 660 feet were left out of the HCA final rule of August 6, 2002 (67 FR 50824). In this proposed rule, we are adding a new proposed HCA component of populated areas in paragraph 192.761 (g). We are proposing to require that an operator consider 20 or more buildings intended for human occupancy within an potential impact circle of radius 1000 feet or larger. We calculated that 20 buildings within a circular area of a 1000-foot radius represent a resident density equivalent to 46 buildings within a rectangular area one mile long and 1320 feet wide (current Class 3 location definition). Therefore, by using 20 or more buildings within circular area of radius 1000 feet we are, including areas having the same density of population as Class 3 locations.

To understand the provisions of this proposed rule, it is necessary to understand both the pipe segments covered by the proposal and the ranking of integrity improvement requirements for those pipe segments. The approach involves the six steps that rely on the definitions below: (1) Identify all HCAs for the pipeline using the HCA definitions as expanded by this proposed rule; (2) calculate the Potential Impact Radius (PIR) for each segment in the pipeline; (3) determine the Threshold Radius associated with the PIR for each segment; (4) identify Potential Impact Circles for the pipeline; (5) identify Potential Impact Zones (PIZ) for the pipeline and in Class 3 and Class 4 locations, identify the moderate risk areas; and (6) determine the priority of each segment covered by this proposed rule—covered segments located within a potential impact zone are considered higher priority, whereas those located outside a PIZ are considered lower priority.

The following proposed definitions help to understand these six steps:

Potential Impact Circle (PIC)—PIC is a circle of radius equal to the threshold radius used to establish higher priority areas within HCAs. A potential impact circle contains any of the following (for greater clarity see the diagram in Appendix E):

- 20 or more buildings intended for human occupancy within a circle of radius 1000 feet, or larger if the threshold radius is greater than 1000 feet;
- A facility that houses people who are difficult to evacuate as defined in § 192.761; or
- A place where people congregate as defined in § 192.761.

Potential Impact Radius (PIR)—PIR means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula $r = 0.69 * (\text{square root of } (p*d^2))$, where ''r'' is the radius of a circular area surrounding the point of failure (ft), ''p'' is the maximum allowable operating pressure (MAOP) in the pipeline segment (psi), and ''d'' is the diameter of the pipeline (inches). (**Note:** 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use Section 3.2 of ASME/ANSI B31.8S to calculate the impact radius formula).

Potential Impact Zone (PIZ)—PIZ is a rectangular area along the pipeline derived from the potential impact circle. The potential impact zone extends axially along the length of the pipeline from the center of the first potential impact circle to the center of the last contiguous potential impact circle, and extends perpendicular to the pipe out to the threshold radius on either side of the centerline of the pipe. For greater clarity see the diagram in Appendix E.

Threshold Radius—Threshold Radius is a bounding radius intended to provide an additional margin of safety beyond the distance calculated to be the potential impact radius. If the calculated potential impacted radius is less than 300 feet, the operator must use a threshold of 300 feet. If the calculated potential impacted radius exceeds 300 feet but is less than 660 feet, the threshold is 660 feet. If the calculated potential impacted radius exceeds 660 feet, but is less than 1000 feet, the threshold is 1000 feet. And, if the calculated potential impact radius exceeds 1000 feet, the threshold is 15% greater than the actual calculated impacted radius.

Pipeline Integrity Management in High Consequence Areas—Proposed Section 192.763

The proposed new § 192.763 titled ''Pipeline integrity management in high consequence areas'' imposes integrity management program requirements on all gas transmission pipelines covered under Part 192 that impact high consequence areas.

The proposed rule requires an operator of a transmission line to develop and follow an integrity management program that provides for continually assessing the integrity of all pipeline segments in the high consequence areas using internal inspection, pressure testing, direct assessment or other equally effective assessment means. The proposed rule further requires that the program provide for evaluating the entire range of threats to the integrity of each pipeline segment through comprehensive information analysis. Further, for each covered pipeline segment, the operator must provide additional protection to a pipeline segment's integrity though remedial actions and enhanced preventive and mitigative measures.

(a) Which Operators Must Comply? Proposed § 192.763(a)

The rule proposes that any operator of a gas transmission pipeline must comply with the integrity management program requirements.

(b) Which Pipeline Segments are Covered? Proposed § 192.763(b)

Any gas transmission pipeline located in a high consequence area, including transmission pipelines transporting petroleum gas, hydrogen, and other gas products covered under Part 192. Gas transmission is defined in § 192.3, and

includes pipelines within storage fields as transmission lines. Thus, this proposed rule covers pipelines within storage fields. Pipeline, by definition, means all parts of those physical facilities through which gas moves in transportation, including pipe, valves and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. The proposed rule does not apply to gas gathering or to gas distribution lines.

(c) What Must an Operator Do? Proposed § 192.763(c)

The rule proposes that no later than one year after the effective date of the final rule, each operator is required to establish a written integrity management program that addresses the threats on each pipeline segment that could impact a high consequence area. The operator would then implement and follow the program it has developed. Initially, the program would consist of a framework. Within one year after the final rule becomes effective, we would expect an operator's integrity management program to consist of:

• Identification of all pipeline segments that are in a high consequence area as defined in § 192.761 (and expanded by this proposed rule). It would also include categorization of whether these segments fall into a potential impact zone. All segments identified will be required to have enhanced integrity protection. The identification of potential impact zones is required to determine the length of baseline assessment intervals for these segments. Because identification of the pipeline segments is the trigger for all other integrity management requirements, the identification must be done within one year from the final rule's effective date. When evaluating the consequences of a failure within the potential impact zone the operator refer to Section 3.3 of ASME/ANSI B31.8S for a minimum set of consequence factors to consider.

• A program framework that addresses each of the required program elements, including continual integrity assessment and evaluation. The framework is required to document how decisions will initially be made to implement each element. To be effective, an integrity management program must constantly change. RSPA/OPS expects that the initial program will consist of a framework that specifies the criteria for making decisions to implement each of the required elements. The program evolves from the framework and must continue to change to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. In addition, the program must evolve to reflect the best practices used in the pipeline industry to assure pipeline integrity. An operator will have to document any change it makes to its program before implementing the change. In addition, if a change is significant enough that it affects the program's implementation or significantly modifies the program, the operator must notify OPS within 30 days of adopting the change into its program. An initial decision on the type of assessment method an operator is going to use is not considered a significant change.

• A plan for baseline assessment of the pipeline. The plan must identify segments to be assessed, applicable threats for each segment, method(s) selected to assess each pipeline segment (including internal inspection tool or tools, pressure test, direct assessment, or other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe), the basis on which each assessment method was selected, and a schedule for completing the baseline integrity assessment. An operator would also have to show that it is conducting the assessment in a manner that minimizes environmental and safety risks. See also the preamble discussion under section 192.763(e).

• A direct assessment plan for operators intending to use one of the direct assessment processes, describing how these processes will be used, including identification of External Corrosion Direct Assessment Regions.

To carry out the requirements of the proposed rule, an operator would, where specified, follow the prescriptive requirements of ASME/ANSI B31.8S, and its appendices, unless the proposed rule provides otherwise, or the operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of safety for the public and their property.

Performance-Based Option. ASME/ANSI B31.8S provides the essential features of both a performance-based and a prescriptive integrity management program. The proposed rule allows an operator to use a performance-based approach if the operator satisfies certain exceptional performance requirements. If the operator satisfies these requirements, the proposal would allow an operator to deviate from certain integrity management performance requirements—the time frame for reassessment, as long as a confirmatory direct assessment were done every seven years, using direct assessment as a primary method without having to satisfy the pre-conditions and the time frames for remediating anomalies found during the assessment.

• *Exceptional Performance.* To show exceptional performance the rule proposes that an operator have completed a baseline assessment of all covered pipeline segments, and at least one other assessment; remediate all anomalies identified in the second assessment according to specified requirements; and incorporate the results and lessons learned from the second assessment into the operator's risk model. An operator would also have to demonstrate that it has an exceptional integrity management program that meets the performance-based requirements of ASME/ANSI B31.8S, has a history of measurable performance improvement, and includes, at minimum:

(A) A state-of-the-art process for risk analysis;

(B) all risk factor data used to support the program;

(C) a state-of-the-art data integration process;

(D) a process that applies lessons learned from assessment of covered pipe segments to pipe segments not covered by this section;

(E) a process for evaluating all incidents, including their causes, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(F) a performance matrix that confirms the continuing performance improvement realized under the performance-based program;

(G) a set of performance measures beyond those that are required that are part of the operator's performance plan and are made accessible in real time to OPS and state pipeline safety enforcement officials; and

(H) an analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all pipe segments.

(d) What Are the Elements of an Integrity Management Program? Proposed § 192.763(d)

The proposed rule requires an operator to include certain minimum elements in its integrity management program that are either specified in the proposed rule or in the ASME/ANSI B31.8S standard. Initially, an operator

must develop a framework describing these elements. The framework describes how each element of the program will be carried out initially and documents expected near-term improvements to be implemented to these processes. Over time, this framework evolves into a program description as the operator learns from its experience and that of other operators, and incorporates that knowledge into an ever-improving process description. The proposed required program elements include:

- A process for identifying all potential threats to pipeline integrity in each high consequence area. Section 2.2 of ANSI/ASME B31.8S standard describes how all significant threats to the pipeline can be grouped into 9 categories. It further regroups these 9 categories of threats into three types: time dependent threats (*e.g.*, external corrosion, internal corrosion, stress corrosion cracking); stable or static threats (*e.g.*, manufacturing related defects (defective pipe seam, defective pipe), welding/fabrication related (defective girth or fabrication weld, wrinkle bend , etc.), equipment failure (gasket, control/relief valve, pump seal, etc.); and time independent threats (*e.g.*, third party damage).
- A baseline assessment plan (discussed in § 192.763(e).
- Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis, (criteria for repair are discussed in B31.8S, Section 7). These criteria recognize that the nature and timing of action related to a defect depend on the severity of the defect. Some require immediate action, some require mitigation over a prescribed period, and some must be monitored to ensure they do not represent a future threat to the integrity of the pipeline. ASME B31.8S, Section 7, also recognizes that the repair threshold an operator chooses for taking action on a recognized defect is related to the time acceptable before a follow-up reassessment is performed. If only very small defects are not mitigated in the pipe, then a longer time is acceptable before reassessment is needed. Repair criteria in Section 7 of ASME B31.8S reflect the current reality that developing assessment techniques, such as direct assessment, are not yet as mature as in-line-inspection and pressure testing. Therefore, operators choosing direct assessment must either excavate all indications, or they must reassess their pipe at shorter time intervals.
- A risk analysis that considers all available information about the integrity of the entire pipeline, evaluates its relevance to each segment within an HCA, and estimates the likelihood and consequences of a failure. Requirements and guidance on the gathering, review and integration of risk factor data is provided in ASME B31.8S, Section 4. Acceptable approaches to analyzing the risks associated with each segment are presented in ASME B31.8S, Section 5. The purpose of this analysis is to utilize the best available information, including operating experience on the entire pipeline, to determine the susceptibility to failure of each segment to each potential threat, then to estimate the relative magnitude of the threat so assessment actions can be prioritized.
- A continual process of assessment and evaluation to maintain a pipeline's integrity: Reassessment intervals for different assessment techniques, pipe stress levels and characteristics of residual defects (*e.g.*, predicted failure pressure, hydro-test pressure, or DA repair scope) are discussed in ASME B31.8S, Section 8, and summarized in Table 8–1.
- Identification of preventive and mitigative measures to protect the high consequence area: ASME B31.8S presents an extensive listing of preventive measures in Section 7. RSPA/OPS expects each operator to evaluate the value of instituting these practices in the light of information on threats posed to each segment and to implement applicable and cost-beneficial measures.
- A performance plan, including methods to measure the effectiveness of the program: Performance measurement is treated in the discussion of performance planning in Section 9 of ASME B31.8S, and candidate measures for each threat are presented in Appendix SP–A.
- A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information. An operator must use qualified persons with the necessary technical expertise to evaluate and analyze the results and data from the integrity assessments, the periodic evaluation, the information analyses, etc. Qualifications for these people must be documented and records made available to verify qualifications.
- A management of change process, as outlined in ASME/ANSI B31.8S, Section 11.
- A quality assurance process, as outlined in ASME/ANSI B31.8S, Section 12.
- A communication plan that includes the elements of ASME/ANSI B31.8S, Section 10, and that includes a process for addressing safety concerns raised by OPS, including safety concerns OPS raises on behalf of a State or local authority with which OPS has an interstate agent agreement.
- A process for providing, by electronic or other means, a copy of the operator's integrity management program to a State authority with which OPS has an interstate agent agreement.
- A process for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

One of the most important elements of an integrity management program is operator qualification. This proposed rule requires an operator to verify that supervisors possess and maintain a thorough knowledge of the integrity management program and its elements for which they are responsible. Individuals who qualify as supervisors for any aspect of integrity management programs must have appropriate training or experience in that area. This proposed rule requires the operator to document requirements for these supervisory individuals and others, who are responsible for gathering and interpreting the results of integrity assessments.

(e) What Must Be in the Baseline Assessment Plan? Proposed § 192.763(e)

The proposed rule requires that an operator must include in its written baseline assessment plan each of the following elements:

- Potential threats to the integrity of each pipeline segment. Candidate threats are discussed in this section under § 192.763(f).
- The method or methods selected to assess the integrity of the line pipe in the high consequence area. The integrity assessment method(s) used must be based on threats to which the segment is susceptible. More than one method and/or tool may be required to address all the threats in the pipeline segment. An operator must assess the integrity of the line pipe by: internal inspection tool or tools capable of detecting corrosion, and any other threats to which the pipe segment is susceptible; pressure test conducted in accordance with subpart J; direct assessment in accordance with the proposed requirements; or other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing to use the other technology option must notify RSPA/OPS 180 days before conducting the assessment. RSPA/OPS expects an operator to make the best use of current and innovative technology in assessing the integrity of the line pipe.

• A schedule for completing the integrity assessment.

• An explanation of the assessment methods the operator selected and an evaluation of risk factors the operator considered in establishing the assessment schedule for the pipeline segments.

• For an operator using direct assessment, a plan that takes into consideration the definition of ECDA and ICDA Regions and the complementary tools to be used for each ECDA regions.

• A process describing how the operator is ensuring that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks (*e.g.,* where would launchers and receivers be placed; how the operator plans to dispose of hydrostatic test water; how low point drains would be tested; what extra attention would be given during excavations.). This proposed requirement applies to any assessment method the operator uses and to the reassessments, not just the baseline assessment.

Direction on the analysis of threats, including the data requirements, and on the selection of assessment techniques is provided in ASME B31.8S, Appendix SP–A.

Internal inspection is one of the most useful tools in an integrity management program. Depending on the threats present, RSPA/OPS expects an operator, with pipelines that are piggable or that can easily be made piggable, to consider using geometry tools (for detecting changes in circumference) and metal loss tools (for determining wall anomalies, or wall loss due to corrosion). Both high resolution and low resolution metal loss tools can be beneficial in integrity assessment. For details of each internal inspection tool, including their selection, capabilities, effectiveness, and use, operators should refer to Section 6 of the ANSI/ASME B31.8S. This standard discusses corrosion/metal loss tools for internal and external corrosion threat, crack detection tools corrosion cracking threat, metal loss or geometry tool for third party and mechanical damage threat.

This proposed rule will allow ''other technology'' as one of the four methods to assess the condition of pipeline segments that could impact high consequence areas. RSPA/OPS expects that as these tools are developed they may become useful assessment tools or as complements to direct assessment tools. We expect these tools could be used where internal inspection tools cannot be used, where pressure testing is not feasible, and where only one type of currently proven direct assessment tool could be used or where pipeline is not easily accessible for direct assessment. Some examples of such applications are, cased piping (*i.e.*, under either a river or road crossing), pipe in frozen ground or where bare pipe needs to be examined. Two examples of emerging technologies currently being reviewed and evaluated by RSPA/OPS are: (1) Long-range ultrasonic testing or guided wave ultrasonic testing for in-service monitoring of corrosion and other metal loss defects; and (2) ''No-Pig'' technology, a tool that can determine internal and external corrosion of the pipeline from above ground.

(f) How Does an Operator Identify Potential Threats to Pipeline Integrity? Proposed § 192.763(f)

The proposed rule requires each operator to identify and evaluate all potential threats to pipeline integrity in each area of potential high consequence. Threats that an operator must consider include, but are not limited to:

• Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

• Static or resident threats such as fabrication or construction defects;

• Time independent threats such as third party damage and outside force damage; and

• The effect of human error.

The nine threat categories that comprise the first three general types of threat are discussed in ASME B31.8S, Appendix SP–A. In this Appendix human error is treated as a contributing factor to many of the major threats rather than as a separate threat. For example, it may be the dominant cause of rupture for third party damage incidents in which the equipment operator attempted to locate the pipeline before beginning excavation, but was given erroneous information about the location of the pipeline. In that Appendix, soil erosion is not treated as a separate threat, but viewed as a contributor to making the pipe more vulnerable to third party damage or outside force damage. Appendix SP–A presents detailed prescriptive requirements for managing the integrity of each of the nine threat categories. These requirements include the minimum data set needed to evaluate the presence of a threat, integrity assessment options, responses and mitigation approaches, assessment intervals and candidate performance measures.

The proposed rule also requires each operator to: (1) Collect data needed to evaluate each threat; (2) integrate numerous risk factors; (3) evaluate the susceptibility of each affected segment to each threat; and (4) prioritize affected segments in accordance with the ASME/ANSI B31.8S. The minimum sets of data needed to evaluate each of the nine threat categories are presented in Appendix SP–A of that standard.

Data integration requirements in the proposed rule should be satisfied by addressing the requirements in ASME/ANSI B31.8S, Section 4. Data integration must go beyond risk modeling to include consideration of specific locations where combination of these risk factors may lead to increased risk significance. Examples of data integration are presented in Section 4 of the referenced standard.

Human error analysis required by the proposed rule should follow the proposed training requirements.

If piping with certain material coating and environmental characteristics is in an HCA and the assessment shows it to be severely corroded, then other similar piping outside the high consequence area must also be evaluated, and mitigated as appropriate. This provision is critical in ensuring that the knowledge accumulated in implementing the integrity management requirements on pipe segments within HCAs is effectively utilized to improve integrity throughout the system.

The following additional requirements and guidance applies to the assessment process:

• Pipelines exposed to threats that represent higher risks should generally be assessed sooner than those with threats that represent lower risk. Thus, for the baseline assessment, 50% of covered segments (the higher risk segments) will have to be assessed within five years if pressure test, internal inspection or alternative equivalent technology is used, and within four years if direct assessment is used. The determination of which segments are at higher risk should be made using methods discussed in ASME B31.8S, Section 5. Here several alternative risk assessment approaches are described for use in ranking segments for integrity assessment.

• Pipelines that operate at a stress level less than 30% SMYS fail differently (*i.e.*, leak rather than rupture) from those operating at higher stress. Therefore, different integrity assurance techniques may be appropriate. These low stress pipes have been shown both by fracture mechanics analysis and by evaluation of failure experience data to fail by leaking, not by rupture. Therefore, the techniques most effective in assuring the integrity of these

pipelines could reasonably involve a combination of integrity assessment techniques and enhanced leak detection.

• The proposed rule applies to transmission pipelines, as that term is defined in § 192.5. There may be some transmission pipelines operating at less than 20% SMYS that are covered by the proposed rule. Pipelines operating at that low stress level are unlikely to rupture and therefore, pose little risk. We have requested comment on establishing longer reassessment intervals for these low stress lines.

• As a part of its regular surveillance program operators would have to determine whether new construction activity or newly identified recreational activity may add pipe segments to those that can affect an HCA. When such conditions are identified, but no less than annually, the operator must reevaluate which pipeline segments can affect HCAs.

(g) How Is the Baseline Assessment To Be Conducted? Proposed § 192.763(g)

The proposed rule requires that an operator must select the assessment technologies best suited to effectively determine the susceptibility to failure of each pipe segment that could impact an area of potentially high consequences. Assessment tool selection should be based first on the threats to which a segment is susceptible, and second on which assessment techniques can reasonably be applied. More than one method and/or tool may be required to address all the threats to which a pipeline segment is susceptible. The order in which assessment is carried out must take into account priorities determined by a risk assessment. In addition, the proposed rule stipulates that an operator must assess the integrity of the line pipe by applying one or more of the techniques below depending on the threats to which the segment is susceptible:

• Internal inspection tool or tools for detecting corrosion and deformation anomalies as appropriate. For guidance on selecting appropriate internal inspection tools an operator must refer to ASME/ANSI B31.8S standard.

• Pressure test conducted in accordance with subpart J of part 192.

• Direct assessment method for external corrosion threats, internal corrosion threats, stress corrosion cracking, and third party damage (if other assessment methods are not feasible). This method must be carried out in accordance with the ASME/ANSI B31.8S standard and the specified proposed requirements.

• Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify RSPA/OPS 180 days before conducting the assessment.

The proposed rule requires operators to evaluate and assess for third party damage. For gas transmission pipe segments in Class 3 and 4 locations, the major cause of failure is third party damage. This probably results from a higher level of excavation activity in higher populated areas, combined with the fact that thicker and stronger pipe in classes 3 and 4 are less susceptible to corrosion failure. The vast majority of third party damage failures (approximately 90%) occur at the time the third party contact occurs. However, a small fraction of these failures are delayed after the initial contact (*e.g.*, the rupture at Edison, New Jersey). Therefore, some consideration needs to be given to delayed failures. The primary cause of delayed failure from third party damage is believed to be cyclic fatigue from pressure cycling. Gas pipelines are not typically subject to this type of pressure fluctuation.

Given the considerations above, it is clear that lowering the risk associated with third party damage requires that the third party damage threat must be addressed through comprehensive preventive measures. In addition, each operator must evaluate whether cyclic fatigue of sufficient magnitude or other loading condition (including ground movement, suspension bridge condition) necessitate a periodic assessment for dents and gouges. These evaluations must assume the presence of deep dents, and determine whether known and anticipated loading conditions would lead to failure of such hypothesized dents. The results of these evaluations together with the criteria used to evaluate the significance of this threat must be documented in the operators integrity management plan. Operators must assess segments which are vulnerable to delayed failure following third party damage using ILI tools such as deformation or geometry tools. Direct assessment may be used as primary assessment method for third party damage, if no other approach is feasible. Direct assessment has been successfully used to screen piping for the presence of significant residual third party damage, thereby supporting evaluation of the need for additional assessment and focusing on the segments where the use of internal inspection tools is most necessary. Under such conditions, it may be used in combination with data collection and integration to evaluate segment susceptibility to third party damage. In addition, operators unable or who believe it unnecessary to use a geometry tool must excavate and directly examine indications from ILI runs or from direct assessment that are suspected of resulting from third party damage. The comprehensive preventive measures employed must be documented in the operators integrity management program, and measures of their effectiveness established and monitored.

To address manufacturing and construction defects (including seam defects), the rule proposes that an operator must a pressure test at least once in the life of the segment unless the operator can document in its assessment plan why pressure testing is not required. At anytime the historic operating pressure or other stress conditions is anticipated to change, then the operator must assess the pipeline using appropriate assessment technology prior to making the change in operating condition. The methods an operator selects to assess low frequency electric resistance welded (ERW) pipe or lap welded pipe susceptible to seam failures must be capable of assessing seam integrity and of detecting corrosion anomalies.

The present understanding of the conditions leading to failure from materials and construction defects has improved significantly as a result of analyzing failure experience. For example, while some pre-1970 ERW piping has experienced failures resulting from seams defects, only certain manufacturers'' pipe has demonstrated susceptibility to this type of failure. In addition, a once-in-a-life pressure test has proven to significantly lower the likelihood of failure in these susceptible pipe segments. Further, piping that has not been hydro-tested has shown susceptibility only when operating parameters are changed significantly. Therefore, careful analysis of industry operating experience and comparison of the root causes of historic failures with the operators pipe will allow operators to determine the risk of failure from these mechanisms. Incident root cause analysis also indicates that any anticipated increase in operational pressure will require the operator to perform a hydro-test prior to changing operational characteristics. This requirement applies even if an operator plans to increase operating pressure from the historic level, but not to exceed the MAOP.

Time period. Each operator must prepare a baseline assessment plan that documents the order in which each pipeline segment will be assessed according to level of risk the segment

poses. Operators must complete the baseline assessment within the specified time frame regardless of the stress level at which the pipeline is operating. The plan for conducting the baseline assessment must, among other considerations, minimize the impact on gas supply to residents.

- An operator using pressure test or internal inspection tool assessment method on a segment located in an HCA and in the potential impact zone must complete the baseline assessment within ten years from December 17, 2002 (the date of enactment of the Pipeline Safety Improvement Act of 2002). An operator must assess at least 50% of the line pipe, beginning with the highest risk pipe, by 5 years from December 17, 2002.
- An operator using pressure test or internal inspection tool assessment method within an HCA but outside of the potential impact zone (also known as a moderate risk area) must complete the baseline assessment within 13 years from December 17, 2002 (the date of enactment of the Pipeline Safety Improvement Act of 2002).
- An operator using direct assessment has seven years to complete the baseline assessment and has to assess at least 50% of the line pipe beginning with the highest risk pipe within four years.
- An operator using direct assessment as an assessment method on a pipeline segment located within a moderate risk area (area in a Class 3 or Class 4 location, but not within the potential impact zone), must complete the baseline assessment of the line pipe within 10 years.

The proposed rule specifies the conditions under which direct assessment can be used as a primary assessment tool. The primary reason that the shorter time frame for completing the assessment using the direct assessment process is that the processes are still developmental, and additional information must be gathered on the method's effectiveness so that any needed adjustments can be made. These adjustments will then be reflected in the second assessment process. The seven-year period is based on RSPA/OPS's assessment of the minimum time needed to collect and analyze risk factor data, to develop internal practices and expertise in application of the processes, and to allow the service industry to develop and qualify people needed to responsibly apply the processes. The time frame selected is compatible with that required for completion of baseline assessments in the hazardous liquid pipeline rule. In addition, the riskiest half of the covered segments have to be assessed during the first four years of the seven-year period.

Prior assessment. The proposed rule allows an operator to use an integrity assessment conducted five years previously from December 17, 2002 (the date of enactment of the Pipeline Safety Improvement Act of 2002) as the baseline assessment if the previous integrity assessment method meets the proposed requirements. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to the proposed reassessment requirements.

Newly-identified areas. When information is available from the information analysis that the population density around a pipeline segment has changed so as to fall within the definition in § 192.761 of a high consequence area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within 10 years (or 7 years if direct assessment is being used) from the date the area is identified.

Background on Direct Assessment. Significant development work was carried out during the past two years to expand the use of indirect assessment tools (*e.g.*, Close Interval Surveys, Direct Current Voltage Gradient, Pipeline Current Mapper, electromagnetic tools) into an integrated integrity assessment process capable of identifying pipeline defects based on a combination of data analysis and integration, above ground assessment, and direct examination. These efforts are resulting in the production of an industry consensus standard on External Corrosion Direct Assessment, and towards the production of standards on direct assessment as applied to internal corrosion and stress corrosion cracking.

RSPA/OPS, along with representatives from several States, participated in the standard development process. This participation led to the identification of several areas where we believe that additional requirements are needed. These additional requirements would help ensure the application of the standards is carried out by competent practitioners, and that innovations developed by more experienced practitioners will be available for use by less experienced operators. Additional requirements could also strengthen those areas where we believe too much discretion is allowed the operator in establishing basic decision criteria needed to apply the Standards. As additional experience is gained in the use of direct assessment processes, RSPA/OPS can consider relaxing these requirements.

(h) When Can Direct Assessment Be Used and Under What Conditions? Proposed § 192.763(h)

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to pipeline integrity. The process includes assembly and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation. The process typically makes use of data on the pipeline, its environment and its operating history to determine the significance of potential threats to integrity and to identify indirect assessment techniques (either analytical or above-ground examination) that an operator can use to determine where a threat possibly damaged the pipeline. Once suspect locations are identified and ranked, then direct physical examination determines the extent of damage and the need for mitigative action. Each threat to which direct assessment is applicable uses a somewhat different process to evaluate the presence of the threat.

While the direct assessment process itself is new, operators have used the analytical techniques, above-ground measurement tools, and direct examination technologies that the process employs, for many years. Examples of above-ground techniques with long prior use include close interval surveys (CIS), direct current voltage gradient (DCVG), and pipeline current mapper (PCM). Examples of direct examination techniques with long prior use include direct physical examination, ultrasonic testing, and x-ray examination.

Why consider allowing the use of direct assessment? Although in-line inspection (pigging) technologies and pressure testing have been used for years, there are several reasons for allowing direct assessment as an assessment method.

INGAA reports that, at present, 24.4% of its members' transmission pipelines are already piggable. According to INGAA, another 25.3% can easily be made piggable, 45.9% (~82,620 miles) would be very costly to pig and 4.4% (~7,920 miles) cannot be pigged. AGA indicates that 35% of its members' pipelines (~4,725 miles) are not piggable. They could only be made

piggable with extensive modifications, at a cost of between $1M and $8M per mile. APGA indicates that the comparable percentage of mileage for its members is 46% (~1,380 miles). Based on these industry-provided numbers, the cost of making the ''very costly'' lines piggable, excluding the increased cost of gas supply due to capacity restrictions, can be estimated to be between $88B and $710B. While these numbers are exceedingly large and rely on the AGA costs, developed for making difficult to pig lines piggable in urban areas, they do indicate that much work on existing lines would be needed to make all gas transmission lines piggable using today's ILI technology. INGAA also argues that pressure testing much of the currently non-piggable pipeline could be costly or impractical because of service interruptions needed to complete the hydro-test, and because the process introduces electrolytes into the system that will be difficult to completely remove, thereby increasing the likelihood for future internal corrosion.

In addition to the feasibility of ILI and the costs associated with making lines piggable, the cost to consumers and the potential of critical supply interruptions are other factors in the RSPA/OPS decision to allow direct assessment. The INGAA study, as mentioned previously, evaluated the cost to consumers associated with capacity restrictions resulting from gas pipe integrity assessment. This study evaluated capacity restrictions and related consumer cost impacts for integrity assessment scenarios involving different mixes of ILI, hydro-test and direct assessment technologies. For a baseline assessment time frame of ten years, the study determined that the difference in cost to the consumer (excluding the cost of making lines piggable) between conducting direct assessment on twenty-five percent and zero percent of piping would be over two billion dollars. Some supply interruptions could also result if direct assessment were not allowed as an alternative assessment technology.

What threats are direct assessment capable of characterizing? Work jointly funded by the gas pipeline industry and RSPA/OPS is ongoing to develop, validate and standardize the application of the direct assessment process to the assessment of external corrosion (ECDA) and internal corrosion (ICDA). Future work is planned to develop, validate and standardize a direct assessment process for application to the stress corrosion cracking (SCCDA) threat. Furthermore, significant anecdotal evidence exists that the ECDA process may be capable of identifying coating damage associated with third party impacts on the pipeline, but formal validation of this capability has not yet been performed.

The current strategy, being incorporated in the developing consensus standard for external corrosion direct assessment for use with the ECDA process, is to locate areas suspected of having external corrosion by identifying defects in the pipe coating, then excavating those defects in areas where corrosion activity is suspected. While all indications discovered by ECDA that are not adequately protected by the cathodic protection system at the time of the assessment will be excavated and directly examined, only a fraction of the ECDA indications that are protected by cathodic protection systems at the time of the assessment will be excavated. This excavation strategy is incorporated in the draft NACE consensus standard on ECDA. The draft standard describes the process by which operators make decisions on the need for continued excavation of features in an ECDA region, based on the severity of defects revealed in previous excavations. If excavation of the indications that are expected to be most severe reveal no significant pipe damage, then further excavations in that region are not necessary. If excavation continues to reveal significant pipe damage, then a larger fraction of protected indications would be excavated.

An approach is under development by the Gas Technology Institute (GTI) for ultimate incorporation in a NACE consensus standard to locate internal corrosion (ICDA). The process, using direct assessment, is focused exclusively on pipe transporting nominally clean dry gas, in which moisture (electrolyte) has been introduced by abnormal operation. Further, it assumes that internal corrosion will only occur if moisture is present at the location in question. The Southwest Research Institute, under GTI funding, developed a mathematical model to predict locations where moisture would accumulate along the line, if it were introduced during an upset condition. These models, together with a common sense approach to identifying other pockets where moisture might accumulate, are to be used to identify areas where excavations and direct examination is required. While not yet validated, this approach is drawn from industry experience and is based on reasonable assumptions about the most likely location of internal corrosion.

There is a need for alternative assessment technologies capable of finding and characterizing pipe defects. RSPA/OPS decided to allow selective use of direct assessment for application in characterizing certain integrity-threatening defects in pipe that cannot (for economic or operational configuration) be pigged or hydro-tested. The conditions for use of direct assessment are based on draft NACE consensus standards with additional requirements that reflect the developmental nature of the processes.

Under What Conditions Can Direct Assessment Be Used?

The proposed rule proposes to allow an operator to use direct assessment as a supplement to the other allowable assessment methods, and to use direct assessment as a primary assessment method for external corrosion, internal corrosion, or stress corrosion cracking only when the operator can demonstrate that a specified condition exists. These conditions are when the other assessment methods cannot be applied to the pipeline segment for economic or technological reasons; the other assessment methods would result in a substantial impact on gas customers; excavation and direct examination will be done on the entire covered pipeline segment; or the covered pipeline segment operates at a maximum allowable operating pressure below 30% SMYS. To use direct assessment as a primary method for external corrosion, internal corrosion or stress corrosion cracking, the operator has to follow ASME/ANSI B31.8S and additional requirements set forth in the proposed rule.

In addition, to use direct assessment as the primary assessment method for third party damage, an operator has to show that no other assessment method is feasible, and that the operator will combine the method with data collection and integration to evaluate the segment's susceptibility to third party damage.

An operator choosing the external corrosion direct assessment (ECDA) method as its primary assessment technology must prepare a detailed plan in which the following information is documented:

- Data requirements for using ECDA; these must include as a minimum the data requirements specified in Appendix SP–A1 for external corrosion in ASME B31.8S.
- Criteria for evaluating ECDA feasibility.
- Criteria for defining ECDA Regions. Further discussion is presented later in this section.

• The basis on which two complementary tools are selected for assessing each ECDA Region. Further information is in Appendix E.

• Criteria for identifying and documenting indications that must later be characterized for severity and considered for direct examination. These criteria must consider, as a minimum, the known sensitivities of assessment tools, the procedures for the use of each tool, and the approach to be used for decreasing the physical spacing at which indirect assessment tool readings are to be taken when presence of a defect is suspected.

• Criteria for characterizing indications identified in the ECDA process. These criteria must define how an indication will be characterized as severe, moderate or minor.

• Criteria for defining the urgency of excavation and direct examination of each indication. These criteria must define the urgency of excavating the indication as immediate, scheduled or monitored.

• Criteria for scheduling excavation of each urgency level of indication. These criteria are discussed at greater length below.

• Criteria for data gathering associated with each excavation.

• Criteria for the qualification of people who carry out and interpret the results from the direct assessment process.

• Criteria and measures for long-term process effectiveness evaluation.

Completion of the Following Four Steps

Step 1: Pre-Assessment—As part of the Pre-Assessment step, the pipeline operator must analyze and integrate the risk factor data to determine whether conditions exist that would preclude the effective use of ECDA. The following conditions may rule out ECDA application or make it difficult to apply. Should any of these conditions exist, the operator must document in the ECDA Plan why ECDA is considered to be valid and the special provisions it will implement to ensure ECDA effectiveness.

• The presence of coatings that cause electrical shielding;

• Backfill around the pipe with significant rock content or the presence of rock ledges;

• Situations impeding timely above-ground data gathering;

• Locations with adjacent buried metallic structures; and

• Inaccessible areas.

As part of the Pre-Assessment step, the operator must select at least two different indirect examination methods for each location where ECDA is to be applied along the pipeline. These methods must be selected based on their ability to detect external corrosion activity and deficiencies in the pipe coating under the conditions expected to be encountered. The tools selected must be complementary, such that the strengths of one tool overlap the limitations of the other. Appendix E presents information to support selection of the two complementary tools. A few examples of indirect examination tools are Close Interval Surveys (CIS), Direct (or Alternate) Current Voltage Gradient (DCVG or ACVG), and electromagnetic techniques (*e.g.*, Pipeline Current Mapper (PCM) and C-Scan).

Direct assessment with only one inspection tool will be permitted to assess for external corrosion only if the operator develops and documents a plan specifying and justifying the special tool or tools being used. The conditions where this deviation is permitted are as follows:

• Pipe in frozen ground;

• Pipe under paved roadways; and

• Pipe in cased crossings (either road or river).

ECDA Region: As part of the Pre-Assessment step, the operator must define ECDA regions. An ''ECDA Region'' is a portion of a pipeline, not necessarily contiguous, that has similar physical characteristics, operating and corrosion history, expected future corrosion conditions, and in which the same indirect assessment tools are used. Due to their similarity, these regions will be used in each of the remaining three steps in the ECDA process. In these subsequent steps, ECDA regions are used to support aggregation and evaluation of indirect and direct examination data. Additionally, ECDA regions may be redefined, or the ECDA process may be determined to be inapplicable for an entire region.

Step 2: Indirect Examination—The operator must carry out the indirect examination step using the tools selected for each ECDA Region. In defining the boundaries for use of each pair of ECDA tools, the operator must ensure completeness of coverage by providing for some overlap between adjacent regions. The following additional provisions must be incorporated when the ECDA process is applied to a segment of pipe:

• Repeat indirect inspections on a sample basis to ensure consistent data are obtained.

• Select intervals for capturing tool readings that are closely spaced enough to ensure consistent data are obtained. Data sampling intervals (locations of test points) for indirect examination tools should typically be no greater than the local depth of coverage of the pipeline.

• Indirect inspections using the two complementary tools in an ECDA Region should be carried out as close together in time as practical.

• Above ground measurements should be geo-referenced and documented so inspection results can be compared and excavation locations accurately identified.

After indirect examination measurements are completed for an ECDA Region, the operator must align the measures taken with the complementary tools and evaluate the consistency of the observations using the following guidance:

• If the results from the two complementary tools are not consistent and cannot be explained by differences in the capabilities of the tools, then either direct examination or additional indirect inspections must be used to evaluate the reasons for the differences.

• If additional indirect inspections or direct examinations are not carried out or if they do not resolve the inconsistencies, then the feasibility of ECDA must be reevaluated.

• Indications must be identified and located following indirect inspection, and the severity of each indication must be classified as severe, moderate or minor using the criteria in the ECDA Plan.

• These classifications should be conservatively developed the first time the process is applied. Results from the Pre-Assessment step (Step 1) must next be compared with prior history for each ECDA Region.

• If assessment results are not consistent with operating history, then the operator must reassess the feasibility of ECDA.

Step 3: Direct Examination (Excavation and Data Gathering)—The operator must next use the results from the indirect examination step to develop and carry out a direct examination plan. The activities to be included in this step are listed below:

• The order and timing of excavations in the direct examination step must be determined from results of the indirect examination step. Both order and timing are derived from a classification of the indications. Criteria developed in the ECDA Plan must be used to determine whether each indication is classified as requiring immediate action, scheduled action or monitoring.

• All indications that are categorized as ''immediate action'' require direct examination (excavation). Should any of these indications be associated with defects that require immediate mitigation, the operator must reduce

operating pressure by at least 20% in the associated ECDA Region and not exceed this pressure until 100% of such indications are excavated, evaluated and mitigated as necessary.

• All excavations of ''immediate action'' indications must be carried out promptly after indirect examination step is complete. An operator must take prompt action to address all anomalous conditions found.

• A minimum of one direct examination (excavation) is required for each ECDA Region. This examination must be made at the most severe indication, based on risk evaluation of the indications. If no indications are shown in the ECDA Region, then the excavation must be made at a location that the operator considers to be the most suspect.

• At least two indications found in each ECDA Region categorized as ''scheduled action,'' require direct examination. Excavation of ''scheduled action'' indications must continue, in priority order, until at least two indications are excavated having corrosion of depth no greater than 20% of the wall thickness.

• The operator must collect all data specified in its ECDA Plan for each excavation completed. These data are to be used in determining the nature and timing of remediation as well as in the fourth step of the ECDA process, the Post Assessment step.

• Except for conditions specified in the body of the rule Section (h)(4), the operator must carry out remediation on a time frame and in a manner specified by ASME B31.8S. Remedial action must be consistent with a determination of remaining strength using ASME B31G, RSTRENG, or equivalent.

• If any exposed segment has significant coating degradation or corrosion, then the operator must increase the size of that excavation until coating and pipe are determined to be adequate.

• The operator must identify the root cause of all significant corrosion activity revealed by excavation.

• When ECDA identifies any defect in an ECDA Region that requires immediate mitigation, or when the root cause of any defect is a condition that ECDA is ineffective at assessing (*e.g.*, MIC or shielded corrosion), then an alternate assessment technology must be used for that ECDA Region.

Step 4: Post-Assessment—The operator must carry out a Post Assessment step to determine the reassessment interval and to evaluate the overall effectiveness of the ECDA process. In carrying out this step, the following requirements apply:

• The reassessment interval must be determined based on the largest defect remaining in the pipe segment and on the corrosion rate appropriate for the pipe, soil and protection conditions. The largest remaining defect must be taken to be the size of the largest defect discovered in the ECDA segment. The corrosion growth rate must be conservatively estimated based on data taken during the direct examination. The reassessment interval must be estimated as half the time required for the largest defect to grow to a critical size.

• An operator that directly examines and appropriately remediates defects consistent with the sampling provisions presented in this rule must reassess each segment at an interval not to exceed every five years.

• An operator that examines all anomalies by excavation and remediates these anomalies may be allowed to extend the reassessment interval from 5 years, as specified in the main body of the rule, paragraph (g)(4)of the proposed rule, to as much as 10 years.

• The operator must define and monitor measures to determine the effectiveness of the ECDA process. Measures should be developed to track: (a) The effectiveness of the overall process (*e.g.*, the change in the calculated reassessment interval); (b) the extent and severity of corrosion found; (c) the number of indications in each classification located on successive applications of ECDA; and (d) the time from discovery of an indication categorized as immediate action or scheduled action to its excavation.

Additional Documentation Requirements: In addition to the ECDA Plan, the operator must document all data on Pre-Assessment, Indirect Examination, verification of indirect examination by excavation, Direct Examination and Post-Assessment, and performance measures. The operator must also have procedures documenting communications requirements among various organizations conducting each step of the direct assessment process.

Internal Corrosion Direct Assessment

Internal corrosion direct assessment (ICDA) is a process that identifies areas along the pipeline where water or other electrolyte introduced by an upset condition may reside, then focuses direct examination on the locations in each area where internal corrosion is most likely to exist. If no evidence of internal corrosion exists in these most likely locations, then the entire section can be considered to be free of internal corrosion. An operator using direct assessment as a method to address internal corrosion in a pipeline segment must follow the requirements in ASME/ANSI B31.8S, Appendix SP–B2, and in this section.

For internal corrosion direct assessment, in addition to requirements in ASME/ANSI B31.8S, Appendix SP–B2, an operator must carry out the process described below. This process consists of four steps: pre-assessment, identification of ICDA regions and excavation locations, direct examination, and post assessment and continuing evaluation. The process is designed to evaluate potential for internal corrosion caused by water, CO2, O2, chlorides, hydrogen sulfide and other contaminants present in the gas, as well as MIC.

Step 1: Pre-assessment—The first step in the ICDA process is pre-assessment. In this step the operator gathers information needed to support identification of areas where internal corrosion is most likely to exist. This step requires the operator to:

• Gather all data elements listed in Appendix SP–A2 of ASME/ANSI B31.8S.

• Assemble information needed to determine where internal corrosion is most likely to occur including: (a) Location of all gas input and withdrawal points on the line; (b) location of all low points on the line such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; (c) the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; (d) the diameter of the pipeline, and the range of expected gas velocities in the pipeline.

• Assemble and evaluate operating experience data that would provide an indication of historic upsets in gas conditions, locations where these upsets have occurred, and any indications of damage resulting from these upset conditions.

Step 2: Identification of ICDA Regions and Excavation Locations—The principal innovation of the gas pipeline industry in its development of the ICDA Process is the capability to evaluate the critical slope of a pipeline beyond which moisture in the gas is unlikely to be carried over. The primary assumptions in this analysis include: (a) For internal corrosion to occur an electrolyte such as water must be present in the pipeline; (b) the gas being transported is nominally clean and dry but may potentially be subject to upset conditions; (c) any entrained moisture carried in the gas stream will either evaporate or accumulate in a film along the wall of the pipe and be carried downstream by the shear force of the gas movement; (d) there is a critical pipe

angle above which gas that is swept along the wall will not progress downstream because the gravitational force will exceed the shear force of the gas on the liquid film.

The purpose of this step is to define ICDA Regions, and to use these regions to identify areas where excavation and direct physical examination of the pipeline is needed to look for internal corrosion. ICDA Regions are regions along the pipeline where internal corrosion may occur and further evaluation is needed. An ICDA Region is bounded by a location where a new gas stream enters the pipe and the nearest location downstream of that point where a the pipe slope exceeds the critical angle, given local gas velocity. The operator identifies these ICDA Regions by applying the results of the mathematical flow model as represented in Graph E.III.1 in Appendix E of this document. Flow modeling must include explicit consideration of changes in pipe diameter as well as locations where gas enters a line (providing potential to introduce moisture) and locations down stream of gas draw-offs (where gas velocity is reduced).

Once the ICDA Regions are identified, the most likely locations for internal corrosion in each region can be identified. A minimum of two locations must be identified for excavation in each ICDA Region. One location is the low point (*e.g.*, sags, drips, valves, manifolds, dead-legs, traps) nearest to the beginning of the ICDA Region. The second location is at the upstream end of the pipe incline nearest the end of the ICDA Region. The first point represents the most likely locations for accumulation of electrolyte in the ICDA Region, and the second point represents the location furthest from the beginning of the ICDA Region where internal corrosion may occur..

Step 3: Direct Examination—At a minimum the operator must excavate the two locations described above, in each ICDA Region where the potential for moisture accumulation exists, and must perform direct examination for internal corrosion by inspecting both locations. Acceptable direct examination technologies are described in ASME/ANSI B31.8S, Appendix SP–B2, and include ultrasonic examination and x-ray.

If no internal corrosion exists at either of these locations, then the remainder of the ICDA Region is likely to be corrosion free. However, if corrosion exists at either of these locations, then either much more extensive excavation is required or an alternative assessment technology (*e.g.*, in-line-inspection) will be required to characterize the pipe for internal corrosion. At any location where indications of metal loss exist, mitigation must be undertaken.

Step 4: Post Assessment and Continuing Evaluation—After completing excavation and needed mitigation of the two suspect locations in each ICDA Region, the operator must document and implement a program of continuing monitoring for segments where internal corrosion has been identified. This program may include use of coupons located in suspected areas, but must include periodic reassessment at the prescribed interval. In addition, fluids drawn off of the pipeline at low points must be retained and chemically analyzed for the presence of corrosion products. Evidence of corrosion products must be interpreted as requiring further excavations of locations down stream where moisture might accumulate, or use of an alternative assessment technology such as in-line-inspection.

Stress Corrosion Cracking (SCC)

As described in ASME/ANSI B31.8S, Appendix SP–B3, direct assessment techniques represent the single most significant historic approach to evaluate for the presence of stress corrosion cracking (SCC). Only recently ILI tools have become available to reliably identify SCC in pipelines, and the use of these tools must be guided by a pre-assessment review that identifies where to look for the possibility of SCC.

For SCC direct assessment, in addition to text in ASME B31.8S standard, an operator must consider the following condition:

- Systematic SCC data collection, evaluation and accumulation process must be instituted for all segments that satisfy the criteria in the ASME B31.8S standard. This process must include gathering and evaluating data related to SCC at all excavation sites where the criteria indicate the potential for SCC.
- If any evidence of SCC is discovered, then the operator must select and implement a suitable assessment approach.

Confirmatory Direct Assessment is a more focused application of the principles and techniques of direct assessment. It utilizes process steps similar to direct assessment to evaluate for the presence of suspected corrosion and third party damage, but it is not as involved as direct assessment. The rule proposes that an operator use confirmatory direct assessment to reassess a pipeline segment within the required seven-year interval if the operator has established a longer reassessment interval for that segment.

For example, in the proposed rule, if an operator is using pressure testing or internal inspection, it could establish a ten-year reassessment interval for a covered segment. By the seventh year, the operator would have to conduct a confirmatory direct assessment on that segment to identify corrosion or third party damage. The operator would then have to conduct the follow up reassessment in the tenth year. If the operator has established a seven-year or shorter interval for the segment, the operator would not have to conduct the confirmatory direct assessment.

The rule proposes that the confirmatory direct assessment method be used to identify internal and external corrosion and third party damage. For external corrosion, an operator's plan to use this method would have to include steps for pre-assessment, indirect examination, direct examination, and remediation.

- The pre-assessment would be the same as that proposed for direct assessment;
- The indirect examination would be the same as that proposed for direct assessment except the examination can be conducted using only one indirect examination tool most suitable for the application.
- The direct examination would follow that for the direct assessment, except that all immediate action indications must be excavated n each ECDA region, and at least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region. No excavation is required for indications categorized as monitored indications.
- The remediation requirements follow those proposed for direct assessment.

For internal corrosion, an operator's plan to use this method would have to include steps for pre-assessment, identification of ICDA Regions, identification of excavation locations, direct examination and remediation.

- The pre-assessment would follow that proposed for direct assessment.
- The identification of ICDA Regions would follow that proposed for direct assessment.
- The identification of excavation locations and excavation would follow that proposed for direct assessment, except that the operator must identify for excavation at least one high risk location in each ICDA Region.
- The direct examination (excavation) and remediation would follow that for direct assessment, except one high risk location in each ICDA Region is to be chosen for excavation.

For identifying third party damage, the operator's confirmatory direct assessment plan would include identification of pipeline segments where construction or other groundbreaking activity was reported near the pipeline right-of-way since the previous assessment.

(i) What Actions Must Be Taken To Address Integrity Issues? Proposed § 192.763(i)

The proposed rule requires that an operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. If an operator is unable to respond within the time limits for certain conditions specified below, operating pressure of the pipeline must be temporary reduced. An operator must determine the temporary reduction in operating pressure for dents and gouges using section 851.42 of ASME/ANSI B31.8; and for corrosion using ASME/ANSI B31G, RSTRENG, or equivalent, or by reducing the operating pressure to a level not exceeding 80% of the level at the time the integrity assessment results were received. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action on anomalies that could reduce a pipeline's integrity. An operator must comply with Section 7 of ASME/ANSI B31.8S when defining the time frame for making a repair. Section 7 of this standard defines conditions for which the required response is ''immediate'' or can be ''scheduled,'' and other conditions for which the indications can be ''monitored.'' ''Immediate response,'' means that upon discovery of the condition the operator will immediately either shut the line down or reduce pressure to 80% of its previous level or less, if necessary to achieve a safe condition, and maintain that lower pressure until the defect is mitigated. Under no circumstances shall this temporary pressure reduction be extended beyond 365 days after the condition is discovered. Immediate response conditions are defined for threats including corrosion, stress corrosion cracking and third party damage. In addition, conditions for which the ratio of the predicted failure pressure to the MAOP is determined to be less than or equal to 1.1, require immediate response. ''Scheduled response,'' means that the indications must be reviewed within six months of discovery and response plans developed consistent with the severity of the defect. Figure 7–1 of ASME/ANSI B31.8S presents criteria for remediation time as a function of the stress level of the pipe and the severity of the defect (*i.e.*, the ratio of the predicted failure pressure to the MAOP). ''Monitored defects,'' are those for which the response time for mitigation is greater than the reassessment interval, and, therefore, the indications will be reexamined as part of the reassessment process.

The proposed rule also defines ''discovery of condition.'' Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination If the operator cannot make the necessary determination within the 180 day period, them it must notify RSPA/OPS of the reasons for the delay and the expected time for completing the assessment.

Except for special requirements for scheduling remediation of certain conditions specified in paragraph (h)(4) of the proposed rule, an operator is required by the proposed rule to follow a threat by threat schedule specified in the ASME/ANSI B31.8S Standard. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify RSPA/OPS if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. An operator must send the notice to the address specified in paragraph (n) of the proposed rule.

The proposed rule also tabulates special conditions for scheduled remediation as follows:

Immediate repair conditions. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. Consistent with ASME B31.8S, Chapter 7, an operator must treat the following conditions as immediate repair conditions:

- A calculation of the remaining strength of the pipe shows a predicted failure pressure less than 1.1 times the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)). These documents are available at the addresses listed in Appendix A to Part 192.
- A dent that has any indication of metal loss, cracking or a stress riser.
- An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action. Such an evaluation is required by all operators using direct assessment.

180-day evaluation. Except for conditions listed in ''immediate repair'' conditions of this section, an operator must complete evaluation and schedule remediation of the following within 180 days of discovery of the condition:

- Calculation of the remaining strength of the pipe shows a predicted failure pressure between 1.1 times the established maximum operating pressure at the location of the anomaly, and the ratio of the predicted failure pressure to the MAOP shown in Figure 7–1 of ASME B31.8S to be appropriate for the stress level of the pipe and the reassessment interval. For example, if the pipe is operating at 50% SMYS and the reassessment interval is ten (10) years, then the predicted failure pressure ratio for scheduling examination and remediation during that ten year period would be 1.39.

180 day remediation. The following conditions must be remediated within 180 days of discovery of the condition:

- A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).
- A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.
- A potential crack indication that when excavated is determined to be a crack.
- Corrosion of or along a longitudinal seam weld.

• A gouge or groove greater than 12.5% of nominal wall.

Scheduled Remediation. The ASME/ANSI B31.8S Standard includes provisions for scheduled repairs over a period exceeding 180 days. For all indications that are not excavated and remediated within 180 days, the following requirements apply:

• For segments assessed using ILI techniques, the failure pressure must be determined and remediation carried out on a time frame consistent with Figure 7–1 in ASME/ANSI B31.8S.

• For segments assessed using direct assessment, at least one direct examination, beyond those required in Paragraph (g)(4) of the proposed rule, of a scheduled indication must be carried out in each ECDA Region between assessments. The results of this direct examination must be compared with those from earlier direct examination results for consistency. Should the defect be larger than any of those identified in previous excavations in that region, then further excavation must be carried out until the requirements in Paragraph (g)(4) of the proposed rule are satisfied.

(j) What Additional Preventive and Mitigative Measures Must an Operator Take To Protect the High Consequence Area? Proposed § 192.763(j)

The proposed rule includes the following general requirement: An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area in accordance with the standard ASME/ANSI B31.8S. Table 7–1 in the ASME standard describes some preventive and mitigative measures appropriate for each threat. In addition, operators must conduct risk analysis of their pipeline segments to identify additional actions to enhance public safety. Such actions include, but are not limited to, installing Automatic Shut-off valves or Remote Control Valves, computerized monitoring and leak detection systems, extensive inspection and maintenance programs, and heavier wall thickness.

Automatic Shut-off valve (ASV) or Remote Control Valves (RCV). If an operator determines that an ASV or RCV is needed on a pipeline segment to protect high consequence areas in the event of gas release, an operator must install the ASV or RCV. In making that determination an operator must at least consider magnitude of leak detection and pipe shutdown capabilities, the type of gas, pressure, the rate of potential release, the potential for ignition, location of nearest response personnel, and benefits expected by reducing the volume of gas release. The operator must document the criteria used in evaluating the need for ASVs and RCVs, and document the decisions resulting from application of these criteria.

(k) What Is a Continual Process of Evaluation and Assessment To Maintain a Pipeline's Integrity? Proposed § 192.763(k)

The integrity assessment requirements proposed in this rule do not stop with the baseline integrity assessment. An operator must, on a continual basis, assess the integrity of the line pipe and evaluate the integrity of each pipeline segment that could affect a high consequence area. The proposed rule requires an operator to conduct a periodic evaluation of each pipeline segment, as frequently as needed, to assure the pipeline's integrity. An operator would determine frequency based on threats specific to the pipeline segment, plus threats specified in proposed § 192.763(e) and in Section 2 of the ANSI/ASME B31.8S Standard.

The evaluation is based in part, on the information analysis the operator conducts of the entire pipeline to determine what history and operations elsewhere could be relevant to the segment. The evaluation must also consider the past and present integrity assessment results, and decisions about repair, and preventive and mitigative actions. The evaluation must be carried out by a person qualified to evaluate the results and other related data.

As with the baseline assessment, the continual integrity assessment method must be by internal inspection, pressure test, direct assessment, or other technology that provides an equivalent understanding of the condition of the line pipe. As with the baseline assessment, if an operator chooses other technology as a reassessment method, the operator must give 90-days advance notice (by mail or facsimile) to RSPA/OPS. As with the baseline assessment, an operator must have a process for ensuring that the assessment is being done in a manner to minimize environmental and safety risks.

Each covered pipeline segment must be reassessed at seven-year intervals, or five years if direct assessment is used and the operator directly examines and remediates defects by sampling. The period for reassessment begins with the completion of the prior assessment on that segment. The proposed rule allows an operator to base the reassessment interval on the risk the pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. If the operator establishes a reassessment interval for the covered segment that is greater than seven years, the operator must within the seven-year period, conduct a reassessment by confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the established interval. The length of the interval will depend on the method of assessment.

If an operator uses pressure testing or internal inspection as an assessment method, the operator must establish the reassessment interval for covered pipeline segments by either basing the intervals on the identified threats for the segment (as identified in the proposed rule and in ASME/ANSI B31.8S, Table 8–2, section 8) and on the analysis of the results from the last integrity assessment and from the required data integration or by using the intervals for different stress levels of pipeline specified in ASME/ANSI B31.8S, Table 8–1, section 8. However, under either option, the maximum reassessment interval must not exceed ten (10) years for a pipeline operating at or above 50% SMYS, and 15 years for a pipeline operating below 50% SMYS. These maximum assessment intervals will be acceptable, only if the operator demonstrates it has enhanced preventive and mitigative programs in place and the operator conducts a confirmatory direct assessment within the seven-year interval.

An operator that establishes the maximum period allowed for reassessment must conduct a confirmatory direct assessment within the seven-year interval and demonstrate that it has implemented enhanced preventive and mitigative measures for the segment.

If an operator uses direct assessment, it must determine the reassessment interval according to a calculation. The reassessment interval cannot exceed five years, if an operator directly examines and remediates defects by sampling, or ten years, if an operator conducts a direct examination of all anomalies and remediates these anomalies. A ten-year interval would necessitate an interim reassessment by confirmatory direct assessment in the seventh year.

The proposed rule requires each operator to evaluate the cause of threats for which mitigative action was undertaken, and determine whether there is reason to reassess the pipe at shorter intervals based on the nature of significant threats. For example, if the dominant cause of pipe deterioration in a particular segment was MIC, then the operator is required to reassess its similar pipe segments on a shorter

interval, consistent with the growth rate of MIC corrosion.

OPS can only allow a waiver of a maximum reassessment interval greater than seven years in two instances—for lack of internal inspection tools or to maintain local product supply- and if OPS determines that such a waiver would not be inconsistent with pipeline safety. Because public notice and comment is required for a waiver, we are proposing an operator provide 180 days advance notification.

The proposed rule requires the operator to assess the integrity of the line pipe by one or more of the following techniques:

- Internal inspection tool or tools; for details on selecting appropriate internal inspection tools an operator must refer to ASME/ANSI B31.8S section 6.2.
- Pressure test conducted in accordance with Subpart J of Part 192.
- Direct assessment method for external corrosion threats, internal corrosion threats, and other threats must be carried out in accordance with the ASME/ANSI B31.8S standard Section 6.3 and paragraph (h) of the proposed rule.
- Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify RSPA/OPS 180 days before conducting the assessment, by sending a notice to the address or to the facsimile number specified in paragraph (n) of the proposed rule.

(l) What Methods To Measure Program Effectiveness Must Be Used? Proposed § 192.763(l)

The proposed rule requires an operator to include in its integrity management program methods to measure the program's effectiveness in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. The proposed rule requires that an operator use four overall performance measures specified in Section 9.4 of ASME/ANSI B31.8S and specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix SP–A.

The performance measures help an operator determine whether all integrity management program objectives were accomplished and whether pipeline integrity and safety are effectively improved through the integrity management program. Proper selection and evaluation of performance measures are an essential activity in determining integrity management program effectiveness. According to ASME/ANSI B31.8S Standard, evaluations must be performed at least annually to provide a continuing measure of integrity management program effectiveness over time. This standard lists four overall program measurements that must be determined and documented. Those measurements are: (1) Number of miles of pipeline inspected versus program requirements; (2) number of immediate repairs completed as a result of integrity management inspection program; (3) number of scheduled repairs completed as result of the integrity management inspection program; (4) number of leaks, failures and incidents.

The proposed rule requires that an operator periodically make available for inspection the four primary performance measures enumerated above from Section 9.4 in ASME/ANSI B31.8S.

(m) What Records Must be Kept? Proposed § 192.763(m)

The proposed rule requires that an operator maintain certain records for inspection, including its written integrity management program, and, if applicable, its plan for using direct assessment. This requirement is not different from the procedural manual an operator is required to maintain for operations, maintenance and emergencies. An operator would also be required to maintain for review during inspection, any documents that support the decisions and analyses made, and actions taken to implement and evaluate each element of the integrity management program. This would include records documenting any modifications, justifications, variances, deviations and determinations made. All records required under direct assessment must also be maintained and available for RSPA/OPS review during inspections. Again, this requirement is no different from the myriad of documents an operator now maintains to comply with the other provisions of the pipeline safety regulations.

(n) Where Does an Operator Send a Notification? Proposed § 192.763(n)

This section of the proposed rule clarifies that any required notification must be sent to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW., Washington, DC 20590, or to the facsimile number (202) 366–7128. Notification is required when an operator: (a) Uses alternative technology for an integrity assessment; (b) cannot meet its schedules for identification of segments and identification of ECDA regions if applicable; (c) cannot meet schedules for evaluating and remediating anomalous conditions; (d) adopts certain changes into its program; and (f) seeks a waiver from a reassessment interval greater than seven years.

Appendix E to Part 192

We are adding a new Appendix E to Part 192. This Appendix gives guidance on determining a potential impact zone within a high consequence area and shows diagram of a potential impact zone under figure E.I.1. This Appendix describes the steps an operator needs to perform in order to determine segments covered under potential impact zones. This Appendix also provides recommendations on how to select external corrosion direct assessment (ECDA) Tools and how to identify ECDA Regions. In addition, this Appendix provides a spreadsheet under Graph E.III.1 for calculating critical angle for liquid hold-up for internal corrosion direct assessment (ICDA).

An operator is required to follow the recommendations on ECDA Tool selection and ECDA Regions, unless the operator notes in its plan the reasons why compliance with all or certain provisions is not necessary to maintain integrity of their specific pipeline system. The Appendix contains recommendations on:

- *Selection of indirect inspection tools for direct assessment:* how selection of indirect inspection tools may vary along a segment; minimum number of tools needed for all ECDA locations and items that should be considered when selecting indirect inspection tools; and conditions under which some indirect inspection tools may not be practical or reliable.
- *Identification of ECDA Regions:* how to (a) Collect appropriate risk factor data; (b) define criteria to identify ECDA regions; and (c) identify locations having similar physical characteristics, soil conditions, corrosion protection maintenance. In addition, guidance on establishing ECDA Regions is presented by illustrating an example of the ECDA regions for a hypothetical pipeline.
- *Internal Corrosion Direct Assessment:* how to calculate critical angle for liquid hold-up using a graph from GRI report GRI–02/0057. The approach helps determine if internal corrosion is likely to or unlikely to exist in a chosen length of pipe.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

The Department of Transportation (DOT) considers this action to be a significant regulatory action under

section 3(f) of Executive Order 12866 (58 FR 51735; October 4, 1993). Therefore, it was forwarded to the Office of Management and Budget. This proposed rule is significant under DOT's regulatory policies and procedures (44 FR 11034: February 26, 1979) because of its significant public and government interest. A regulatory evaluation of this proposed rule on Integrity Management for gas transmission pipelines has been prepared and placed in the docket.

Cost-Benefit Analysis

A copy of the draft regulatory evaluation has been placed in the docket for this proposed rule. The following section summarizes the draft regulatory evaluation's findings.

Natural and other gas pipeline ruptures can adversely affect human health and property. However, the magnitude of this impact differs from area to area. There are some areas in which the impact of an accident will be more significant than it would be in others due to concentrations of people who could be affected. Because of the potential for dire consequences of pipeline failures in certain areas, these areas merit a higher level of protection. RSPA/OPS is proposing this regulation to afford the necessary additional protection to these high consequence areas.

Numerous investigations by RSPA/OPS and the National Transportation Safety Board (NTSB) have highlighted the importance of protecting the public and environmentally sensitive areas from pipeline failures. NTSB has made several recommendations to ensure the integrity of pipelines near populated and environmentally sensitive areas. These recommendations included requiring periodic testing and inspection to identify corrosion and other damage, establishing criteria to determine appropriate intervals for inspections and tests, determining hazards to public safety from electric resistance welded pipe and requiring installation of automatic or remotely-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipelines.

Congress also directed RSPA/OPS to undertake additional safety measures in areas that are densely populated. These statutory requirements included having RSPA/OPS prescribe standards for identifying pipelines in high density population area and issue standards requiring periodic inspections using internal inspection devices on pipelines in densely-populated and environmentally sensitive areas, and to require reassessment of these areas at least every seven years.

This proposed rulemaking addresses the target problem described above, and is a comprehensive approach to certain NTSB recommendations and Congressional mandates, as well as pipeline safety and environmental issues raised over the years.

This proposed rule focuses on a systematic approach to integrity management to reduce the potential for natural and other gas transmission pipeline failures that could affect populated areas. This proposed rulemaking requires pipeline operators to develop and follow an integrity management program that continually assesses, through internal inspection, pressure testing, direct assessment or equivalent alternative technology, the integrity of those pipeline segments that could affect areas we have defined as high consequence areas *i.e.*, areas with specified population densities, buildings containing populations of limited mobility, and areas where people gather that occur along the route of the pipeline. The program must also evaluate the segments through comprehensive information analysis, remediate integrity problems and provide additional protection through preventive and mitigative measures.

This proposed rule (the third in a series of integrity management program regulations) covers operators of transmission pipelines for natural and other gases. RSPA/OPS chose to start the series with hazardous liquid pipeline operators because the pipelines they operate have the greatest potential to adversely affect the environment. This proposed rule completes the application of integrity management to all interstate (and many intrastate) pipelines.

We have estimated the cost for operators to identify pipeline segments that can affect high consequence areas at approximately $23.34 million, the cost to develop the necessary programs at approximately $90.9 million (with an additional one-time cost of $367,400 to provide RSPA/OPS and state inspectors with real-time access to performance measures) and an annual cost for program upkeep and reporting of $13.36 million. An operator's program begins with a baseline assessment plan and a framework that addresses each required program element. The framework indicates how decisions will be made to implement each element. As decisions are made and operators evaluate the effectiveness of the program in protecting high consequence areas, the program will be updated and improved, as needed.

The proposed rule requires a baseline assessment of covered pipeline segments through internal inspection, pressure test, direct assessment or use of other technology capable of equivalent performance. Unless an operator uses direct assessment, the baseline assessment must be completed within ten years after December 17, 2002 (the date the Pipeline Safety Improvement Act of 2002 was signed into law), with at least 50% of covered segments being assessed within five years. With direct assessment the baseline assessment must be completed in seven years, with 50% of the covered segments completed within four and 1/2 years. Until we see the results from operators' assessments we cannot determine whether direct assessment by itself is adequate to assess pipeline integrity or whether pigging might also be needed. The period for a baseline assessment may extend to 13 years, or ten years for direct assessment, for segments in moderate risk areas, that is, areas within a class 3 or 4 location that are not in the impact zone from a potential rupture.

After this baseline assessment, the rule further proposes that an operator periodically reassess and evaluate the pipeline segment to ensure its integrity within a ten-year interval for pipelines operating at greater than 50 percent of specified minimum yield strength (SMYS) and a fifteen-year interval for pipelines operating below 50 percent SMYS. However, to meet the requirements of the Pipeline Safety Improvement Act of 2002, if an operator establishes an interval greater than seven years, the operator will need to conduct an interim reassessment by the seventh year using a more-focused direct assessment (Confirmatory Direct Assessment) method. If an operator elects to perform a reassessment, using one of the other methods, every seven years, the operator need not use the confirmatory direct assessment. The proposed reassessment interval for pipelines assessed with direct assessment is five years unless all anomalies are excavated, in which case it is ten years.

Confirmatory direct assessment is a more-focused application of the principles and techniques of direct assessment, that is concentrated on identifying critical segments of suspected corrosion and third party damage. RSPA/OPS has structured the proposed requirements for confirmatory direct assessment in a manner intended to allow maximum flexibility for operators. Indirect examinations may be performed using only one, rather than two, tools. Corrosion regions may be larger than for regular direct

assessments. The number of excavations required per region is less. These changes will allow operators to plan and conduct confirmatory direct assessments in a manner that is most cost-effective, *i.e.*, identifies areas of concern at lowest cost.

There is no data available at present regarding the cost to implement confirmatory direct assessment. The flexibility included in these proposed requirements means that costs may vary depending on assumptions the operator makes in planning and conducting these assessments. For purposes of this evaluation, the RSPA/OPS assumes that the cost will be less than, but more than half, that of direct assessment, or $3,000 per mile. Actual costs for many operators may be lower, and the total cost estimates in this analysis are thus expected to be conservatively high.

It is estimated that the cost of periodic reassessment will generally not occur until the sixth year (when reassessment costs will begin for a pipeline baseline assessed using direct assessment) unless the baseline assessment indicates significant defects that would require earlier reassessment.

RSPA/OPS believes that the higher the operating pressure of a pipeline, the greater the potential risk the pipeline poses to the general public. That is because a failure of a pipeline operating at a higher pressure will result in a larger impact area and potentially more significant consequences. It is under this assumption that RSPA/OPS is proposing the shortest assessments intervals for pipelines that operate at or above pressures of 50 percent of SMYS. By basing the assessment interval according to pipeline pressure, operators will have to focus their safety resources on lines that pose the greatest danger. RSPA/OPS believes that varying the assessment interval according to the risk provides the greatest reward per dollar of safety operators will expend.

Integrating information related to the pipeline's integrity is a key element of the integrity management program. Costs will be incurred in realigning existing data systems to permit integration and in analysis of the integrated data by knowledgeable pipeline safety professionals. The total costs for the information integration requirements in this proposed rule are $31.5 million in the first year and $15.75 million annually thereafter.

The proposed rule requires operators to evaluate the risk of pipeline segments that can affect high consequence areas to determine if additional preventive or mitigative measures that would enhance public safety should be implemented. One of the many additional preventive or mitigative actions that the notice proposes an operator take is to install automatic shutoff valves or remotely controlled valves. RSPA/OPS could not estimate the total cost of installing such valves because there are too many factors that would have to be analyzed in order to produce a valid estimate of how many operators will install them. However, based on the results of a generic feasibility study on remotely controlled valves that RSPA/OPS completed in 1999, we concluded that conversion of existing sectional block valves to remote operation was not economically feasible. Operator- and location-specific factors could change this conclusion for individual valves but RSPA/OPS could not analyze these specific factors for individual block valves and therefore, did not estimate the total cost for installing remote valves. RSPA/OPS presumes that operators will analyze valve-specific factors and will not replace valves unless that action is cost-beneficial. RSPA/OPS estimates that the cost to operators to perform the required risk analyses will be approximately $24.1 million.

Affected operators will be required to assess more line pipe in segments that could affect high consequence areas as a result of this proposed rule than they would have been expected to assess if the proposed rule had not been issued. Integrity assessment consists of a baseline assessment, and subsequent reassessment. The period in which baseline assessments must be completed depends upon the assessment method chosen and the grade of the high consequence areas. The baseline period for most pipe is ten years for pipeline to be assessed with in-line inspection or hydrostatic testing and five years for pipeline to be assessed using direct assessment. These periods are extended to 13 and 7 years, respectively, for pipeline that can affect lower grade high consequence areas, containing relatively lower population densities. Reassessments must be conducted at no less than ten year intervals for pipeline operating above 50 percent SMYS and 15 years for pipeline operating at less than 50 percent SMYS. The proposed reassessment interval for pipe assessed with direct assessment is five years unless all anomalies are excavated, in which case the interval may be extended to ten years. Confirmatory direct assessments would be required to be performed at least every seven years, if an operator established a reassessment interval longer than seven years.

RSPA/OPS analyzed two scenarios, varying the amount of pipeline that operators are expected to modify to accommodate in-line inspection. This approach was taken, because of industry comments that significant amounts of pipeline would likely be modified and the costs for that work. Some pipe already can accommodate in-line inspection tools. Some can be modified to accommodate the in-line inspection tools with relatively simple modifications. Others require much more extensive retrofits. Until we see results of operators assessments we can not judge whether direct assessment is sufficient or pigging is needed. One of the analyzed scenarios assumed that only the piping that can easily be modified would be changed. The other scenario was based on the assumption that a portion of the pipe requiring more extensive changes would also be modified. As a result of this work, RSPA/OPS has estimated the annual cost of additional baseline assessment that will be required by this proposed rule as between approximately $59 million and $298 million annually. The cost for additional re-assessment is estimated at approximately $32 million per year.

Although there are a variety of benefits associated with this proposed rule, the principal benefits are difficult, if not impossible, to quantify. The proposed integrity management program requirements will ensure that all gas transmission operators perform at least to an established baseline safety level and will raise the overall level of safety performance nationwide. The proposed rule will lead to greater uniformity in how risk is evaluated and addressed and will provide a better and clearer basis for government, industry and the public to discuss safety concerns and how they can be resolved. Public awareness of the integrity program will lead citizens to be more informed about pipeline safety and provide information to operators about activities on the pipeline right-of-way that will help to improve safety. The integrated integrity management programs that operators will be required to implement in response to this proposed rule will result in a higher level of safety, which should in turn result in improved public confidence in the safety of natural gas transmission pipelines. Operators have begun integrity programs on their own because they have recognized the importance of knowing the condition of their pipelines and having the public assured that the lines are safe. After a major pipeline accident, and the accompanying national spotlight from the media the public becomes alarmed with the potential threat that pipelines pose. Pipelines that are presently unpiggable

have most likely not been inspected. The public becomes very concerned when it becomes aware that ''aging'' pipelines underground in their community have never been internally inspected. The only method to reassure the public of the safety of pipelines is that there are requirements that these pipelines be internally inspected and evaluated on a periodic basis. This improved confidence is consistent with the objectives of the Administration's National Energy Plan. The importance of integrity management is also reflected in its inclusion in the requirements of the Pipeline Safety Improvement Act of 2002.

RSPA/OPS, as well as the pipeline industry has gained valuable knowledge from accidents and near misses in the 90's. RSPA/OPS has found that operators have gathered valuable information but that they have not used that information effectively or used it to maximum effect. Analysis of recent major accidents indicates that better use of existing information through data integration and evaluation has the potential to prevent major accidents. Data integration requirements should lead operators to make better and more informed decisions about what preventive and mitigative actions to take and how to set priorities. RSPA/OPS believes that it is possible for operators to gather and integrate the necessary data and implement the needed changes with little additional investment.

The benefits that can be quantified are expected reductions in deaths, serious injuries, and property damage costs resulting from accidents on gas transmission pipelines. RSPA/OPS has developed a level-of-magnitude estimate of these benefits. That estimate is based on the accident data reported to RSPA/OPS over a sixteen year period (1986 to 2001). RSPA/OPS estimates that the benefit of completely eliminating the fatalities, serious injuries, and property damage caused by those accidents would be equivalent to approximately $53.25 million per year. RSPA/OPS does not expect that this rule will eliminate all accidents on natural gas transmission pipelines that would result in deaths, serious injuries, or property damage. RSPA/OPS does expect that the proposed rule will significantly reduce the frequency and consequences of such accidents. The magnitude of the expected reduction cannot now be estimated with certainty. RSPA/OPS concludes, however, that the reduction will be significant.

RSPA/OPS notes that the consequences of future accidents, in the absence of any new actions to improve pipeline safety, would likely be higher than would be indicated by historical precedents. The reason for this is continued increase in the population living near, and utilizing land near, pipelines. Accidents that occur in rural settings typically have resulted in fewer deaths, serious injuries, and property damage than accidents that occur in developed areas. As the amount of development near pipelines increases, relatively more accidents would be expected to occur in developed areas and the consequences of those accidents would be expected to increase.

As a result of these factors, RSPA/OPS concludes that the quantifiable benefits of the proposed rule are on the order of $40 million per year. This is less than, but on the same order of magnitude as, the continuing costs. Initial costs, for program development and modification of pipelines to facilitate testing, are significantly higher. The quantifiable benefits alone cannot justify those costs. They need not, however. Recently, gas transmission pipeline operators have indicated that, of the choices of testing available, they frequently are going to choose internal inspection as the best long term investment and while the costs are higher for the modifications needed to operate this method, the operators clearly think the investment is worthwhile.

The principal benefit to be derived from the proposed rule is one that cannot easily be quantified. That is improved public confidence in pipeline safety. That confidence has been shaken by accidents in recent years. It is necessary that actions be taken to restore that confidence. Improved public confidence in pipeline safety will, in turn, produce additional benefit. It will result in improved ability to site and construct the additional pipelines that will be needed to serve growing demand for natural gas in the United States, as indicated in the National Energy Plan. This growth results not only from increasing population, but from increased use of natural gas, as an environmentally desirable fuel, for generating electricity and other industrial uses. Inability to meet these increased demands will challenge our nation's ability to realized desired environmental goals.

RSPA/OPS discussed the draft regulatory analysis with the Technical Pipeline Safety Standards Committee (TPSSC) at a public meeting on July 18, 2002. The TPSSC, composed equally of representatives of industry, government, and groups representative of public involvement in pipeline safety issues, provided numerous comments on the draft analysis. Industry members of the TPSSC indicated that, to a much greater degree than RSPA/OPS had estimated, the industry would choose to modify existing pipeline to make it possible to inspect using in-line inspection tools. The TPSSC also commented that costs had been greatly underestimated, primarily because the additional mileage they will need to internally inspect in order to inspect segments that can affect high and lower risk areas will be much larger than the amount estimated in the draft regulatory analysis. The much larger total amount of mileage that will require inspection could lead to supply disruptions while testing and repair is underway. Nevertheless, the committee unanimously concluded that the expected benefit in terms of improved public confidence in pipeline safety is substantial and justifies the expected costs and that with edits, the RSPA/OPS draft regulatory analysis provided a basis for proposing this rule. RSPA/OPS has revised the draft regulatory analysis in response to the TPSSC comments.

With the increased understanding of the condition of the pipeline that will result from the added assessments and repairs required in the proposed rule, there is the potential for pressures to be maintained that would otherwise have to be reduced to allow adequate safety margins. Additional demand for supply may potentially be better met by not having to impose restrictions to the flow of natural gas through existing transmission pipelines in areas where population is increasing and pipe replacement or pressure reductions would be required. Current requirements provide that natural gas transmission pipelines in areas that would be defined as high consequence areas operate at pressures that limit stresses in the pipe walls to levels significantly below those allowed in more rural areas. The reduced stresses are intended to provide additional margin against accidents that might result from unknown damage or degradation mechanisms. The proposed requirements would result in operators inspecting for, identifying, and remediating such damage. RSPA/OPS has experience, through the Risk Management Demonstration Program, that indicates that the improved confidence in pipeline integrity afforded by the type of integrated integrity management program required by this rule can lead RSPA/OPS to allow operation at higher pressures in these areas. Down the road with the program, applying that experience may make it possible for RSPA/OPS to approve operation of pipelines in some areas at higher pressures, allowing additional

natural gas to be supplied by the existing infrastructure. (The particular circumstances of each area would have to be taken into account in deciding whether operation at increased pressure is acceptable).

The quantitative estimates of benefits also considers only direct effects, *i.e.*, damages caused by the explosion and fire resulting from a natural gas transmission pipeline rupture. There are other consequences of such accidents that can be avoided or prevented. Unplanned business interruption can have a severe economic impact on the area in which an accident occurs. Temporary cessations in operation, longer term pressure restrictions, and repair efforts often require interruption of natural gas supply to some customers. In some areas, this can include entire communities that may be served by sole source laterals receiving gas from transmission lines in the vicinity of the accident. Interruption of natural gas service has both economic and safety consequences. Service must be restored in a controlled manner to avoid subsequent explosions from natural gas escaping into businesses and residences from open pilot valves. Gas distribution company employees must enter each customer's premises, isolate pilot valves, purge piping of air that may have become entrained, and relight pilot lights. This is a labor intensive effort that can take several days for a moderately-sized community. An integrity management program will allow an operator to identify and repair defects that could lead to accidents before they occur. Since these tests and repairs can be planned, their performance can be done at the optimum time to minimize detrimental effects on businesses, homes and supply generally.

Consistent with RSPA/OPS practice, much of the proposed rule is written in performance-based language. This approach stimulates the development and use of new technologies for assessing pipeline integrity which may allow more accurate detection of problems that can now be found or detection of problems that have heretofore been difficult to find.

The performance approach also results in supporting operators' development of more formal, structured risk evaluation programs and RSPA/OPS's evaluation of the programs. Most important, the performance approach encourages a balanced program, addressing the range of prevention and mitigation needs and avoiding reliance on any single tool or overemphasis on any single cause of failure. This will lead to addressing the most significant risks in the most effective manner. This integrity-based approach provides a good opportunity to improve industry performance and assure that these high consequence areas get the protection they need.

A particularly significant benefit is the quality of information that will be gathered as a result of this proposal to aid operators' decisions about providing additional protections. Two essential elements of the integrity management program are that an operator continually assesses and evaluates the pipeline's integrity, and performs an analysis that integrates all available information about the pipeline's integrity. The process of planning, assessment and evaluation will provide operators with better data on which to judge a pipeline's condition and the location of potential problems that must be addressed.

Integrating this data with the safety concerns associated with high consequence areas will help prompt operators and the Federal and state governments to focus time and resources on potential risks and consequences that require greater scrutiny and the need for more intensive preventive and mitigation measures. If baseline and periodic assessment data is not evaluated in the proper context, it is of little or no value. It is imperative that the information an operator gathers is assessed in a systematic way as part of the operator's ongoing examination of all threats to the pipeline integrity. The proposed rule is intended to accomplish that.

The proposed rule has also stimulated the pipeline industry to develop supplemental consensus standards to support risk-based approaches to integrity management. These standards will lead to better quality control on a national basis, particularly important in the area of using new assessment technologies where correct application is critical to achieving the desired safety outcome. Without such standards, there have been instances of incorrect application of assessment technology leading to incidents. These and future incidents of this type can be avoided.

The proposed rule provides for a verification process, which gives the regulator a better opportunity to influence the methods of assessment and the interpretation of results. RSPA/OPS will provide a beneficial challenge to the adequacy of an operator's decision process. Requiring operators to use the integrity management process, and having regulators validate the adequacy and implementation of this process, should expedite the operators' rates of remedial action, thereby strengthening the pipeline system and reducing the public's exposure to risk.

RSPA/OPS does not believe that requiring this comprehensive process, including the re-assessment of pipelines in high consequence areas at the proposed intervals, will be an undue burden on natural and other gas transmission pipeline operators covered by this proposal. RSPA/OPS believes the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in populated areas is benefit enough to promulgate these requirements.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.* RSPA/OPS must consider whether this rulemaking would have a significant impact on a substantial number of small entities. RSPA/OPS estimates that there are 668 gas transmission operators that could potentially be impacted by this proposed rulemaking. This data comes from RSPA/OPS user fee data base. A pipeline company would be impacted if its pipeline could effect a high consequence area (HCA). HCA's are located primarily urban areas but include rural areas where more than 20 people congregate.

The Small Business Administration (SBA) defines small entities in the gas transmission industry as those with revenues of less than $6 million annually. RSPA/OPS does not collect information on operator revenues. The Census Bureau however does collect data on natural gas transmission pipeline companies. Natural gas transmission companies are listed under North American Industry Classification System (NAICS) 486210 Pipeline Transmission of Natural Gas. The 1977 Census lists 1,450 establishments. Establishments in the case of gas transmission companies means unique pipelines. Seven hundred and fifty two of these establishments have revenues under $5 million annually. These establishments are aggregated into firms. NAICS 486210 has 155 firms. Seventy-one of these firms have revenues of less than $5 million annually and could be considered small entities under the SBA.

It is evident from the discussion above that several of the 668 transmission operators reporting to RSPA/OPS are in fact establishments and not firms. RSPA/OPS does not have information on how many unique firms there are among the establishments that report.

RSPA/OPS does not have detailed information on the number of small entities in the gas transmission industry.

Some of the companies in the Census Bureau's figures are gas distribution companies that have transmission lines that serves their gas distribution business. Many of these transmission lines that serve gas distribution companies may be in HCA's. Other limited mileage transmission lines serve the fuel needs of one industrial plant. Many of these industrial transmission lines may be in rural areas and outside the scope of this proposed rule.

RSPA/OPS has never received comments from small gas transmission operators concerning the burdens of its regulations. While RSPA/OPS believes that the costs of this proposal will be proportionate to the amount of mileage the pipeline company operates RSPA/OPS, seeks public input on any potential undue impact that this proposal would have on any small entities.

INGAA estimates that its members account for 80% of the gas pipeline transmission mileage in the United States. INGAA has only 24 members however, 3 of these members are not U.S. gas transmission operators. Therefore, approximately 21 companies account for 80% of the U.S. gas transmission pipeline mileage. The remainder of the pipeline companies in this industry share only 20% of the total pipeline mileage.

Because the remaining companies have relatively small mileage compared to the top 20, many may fall entirely outside of HCA's, and will therefore not be impacted by this proposed rule. However, if they are impacted by this proposal, their costs of compliance will be significantly lower than those with thousands of miles of pipeline as the costs of inspection and planning should be considerably lower. Nevertheless, RSPA/OPS stands ready to provide special help to any small operators to assist them in complying with this proposed rule. Based on the above discussion I certify that this proposed rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This proposed rule contains information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), the Department of Transportation has submitted a copy of the Paperwork Reduction Act analysis to the Office of Management and Budget for its review. The name of the information collection is ''Pipeline Integrity Management in High Consequence Areas Gas Transmission Pipeline Operators.'' The purpose of this information collection is designed to require operators of gas transmission pipelines to develop a program to provide direct integrity testing and evaluation of gas transmission pipelines in high consequence areas.

The following is a summary of the highlights of the paperwork reduction act analysis. The complete analysis can be found in the public docket.

There are 668 gas transmission operators that could potentially be subject to this proposed rule. It is estimated that 296 of these gas transmission operators have 40 or more miles of pipeline. The remaining 372 operators have less than 40 miles of pipeline. It is estimated that the operators with more than 40 miles of pipeline will have considerably more time and expense to develop integrity management programs. However, before operators can develop integrity management programs they must determine how much of their pipeline is located in high consequence areas (HCA's). It is estimated that it will take the operators with 40 or more miles of pipeline 1,000 hours to estimated the amount of pipeline impacted. Operators with less than 40 miles of pipeline will take only 250 hours.

It is estimated that operators with 40 or more miles of pipeline will need 3,968 hours to develop an integrity management plan framework. For operators with less than 40 miles of pipeline it is estimated this task will take 2,400 hours. However, it is estimated that 25% of the companies with more 40 miles or more of pipeline already have integrity management program frameworks.

Additionally, all the operators will be required to integrate the new data they collect into their current management systems. The time to integrate the data the first year will be 2,040 hours for the companies with 40 or more miles of pipeline and 510 hours for companies with less than 40 miles of pipeline. It is estimated that 25% of all operators with 40 or more miles of pipeline already have a system for integrate their data.

It will take operators initially, approximately 16 hours of a computer programmer's time to provide OPS and state pipeline safety offices ''real time'' access to their performance measures via the operator's web site or a dial-up modem.

The integrity management plans need to be modified on a yearly basis. RSPA/OPS estimates that it will take all operators regardless of size 313 hours per year to update their plans annually. RSPA/OPS further estimates it will take an additional 160 hours per operator to perform the necessary record keeping annually. Finally RSPA/OPS estimates it will take operators with 40 or more miles of pipeline 1020 hours to annually integrate the necessary data. It will take operators with less than 40 miles of pipeline approximately 255 hours to annually integrate the necessary data.

Comments concerning this information collection should include the docket number of this proposal. They should be sent to Docket Facility, U.S. Department of Transportation, Plaza 401, 400 Seventh Street, SW, Washington, DC 20590–0001. Comments are specifically requested concerning:

Whether the collection is necessary for the proper performance of the functions of the Department, including whether the information would have a practical use;

The accuracy of the Department's estimate of the burden of collection of information including the validity of assumptions used;

The quality, usefulness and clarity of the information to be collected; and minimizing 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 *e.g.*, permitting electronic submission of responses.

According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless a valid OMB control number is displayed. The valid OMB control number for this information collection will be published in the **Federal Register** after it is approved by the OMB. For details see, the complete Paperwork Reduction analysis available for copying and review in the public docket.

Executive Order 13084

This proposed rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13084 (''Consultation and Coordination with Indian Tribal Governments''). Because this proposed rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

This proposed rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism''). This proposed rule does not propose any regulation that:

(1) Has 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;

(2) Imposes substantial direct compliance costs on States and local governments; or

(3) Preempts state law.

Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255; August 10, 1999) do not apply. Nevertheless, in November 18–19, 1999, and in February 12–14, 2001 public meetings, RSPA/OPS invited National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Since then, RSPA/OPS has held conference calls with NAPSR, to receive their input before proposing an HCA definition and integrity management rule.

Executive Order 13211

This rulemaking is not a ''significant energy action'' within the meaning of Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use''). It is a significant regulatory action under Executive Order 12866 because of its significant public and government interest. As concluded from our Energy Impact Statement below it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

Summary of the Energy Impact Statement

(For a detailed Energy Impact Statement, please refer to Docket RSPA–00–7666)

RSPA/OPS is currently proposing regulations to assess, evaluate, remediate, and validate the integrity of natural gas transmission pipelines through comprehensive analysis and inspection of pipeline systems. The proposed rule applies to all gas transmission lines, including lines transporting petroleum gas, hydrogen, and other gas products covered under 49 CFR Part 192.

In compliance with the Executive Order 13211 (66 FR 28355), RSPA/OPS has evaluated the effects of proposed rule on energy supply, distribution, or use. RSPA/OPS has determined that this proposed regulatory action will not have significant adverse effects on energy supply, distribution, or use.

The proposed rule will not have any significant impact on the wellhead production capacity or prices. The proposed rule affects natural gas transmission lines in high consequence areas (HCAs) and has no effect on the wellhead production capacity or prices. The proposed rule does not impact gathering lines and offshore transmission lines, and has limited effect on the onshore transmission lines that are not located in the HCAs. Therefore, the proposed rule will have no significant impact on natural gas production or wellhead prices. RSPA/OPS estimates that the proposed rule will directly affect 42,268 miles of transmission lines in a network of 300,000 miles of transmission lines, as well as 900,000 miles of distribution lines. Therefore, a relatively small proportion of pipelines will be affected by the proposed rule.

The proposed rule may affect the movement of natural gas in certain areas during integrity inspection. Inspection requirements may temporarily affect transportation capacity in some pipelines. Built-in redundancies, such as, loop lines, multiple lines, storage facilities, are part of natural gas transportation infrastructures. The intricate interconnections between pipelines, the availability of storage at the market centers, and a well-developed capacity release market all contribute towards meeting natural gas demand with efficient movement of supply. Most inspections can be conducted without any significant disruption of throughput especially during off-peak seasons.

The proposed rule may not have any significant price effects on end-use consumers. In general, inter-fuel competition and gas-storage availability play significant roles in short-term price determination in U.S. because of extensive fuel switching capability in industry and power generation and the existence of a sizable storage capacity. Weather is the other significant player determining the spot market prices. Transportation cost only accounts for a small proportion of the cost paid by the end-users. The pipeline capacity reduction due to the proposed integrity rule may to a large extent be pre-planned and the market would have time to adjust for the reduction, minimizing shortages and avoiding short-term price increases.

However, because the percentage of assessments that the industry maintains will be done by internal inspection, much more than 42,268 miles of pipeline cited earlier may in fact be assessed. The reason for this is because internal inspection devices are inserted and removed from the pipeline segment near compressor stations which are up to 50 miles apart. The HCAs may be only a few miles of this entire 50 mile section. The industry maintains that 50% of all lines or approximately 150,000 miles of all gas pipelines will be internally inspected. If this is correct then, temporary impact on local gas supplies may be realized. While RSPA/OPS did not estimate the size of such temporary impacts it could lead to small changes in natural gas prices for certain areas on the spot market. Not withstanding possible temporary price fluctuations in the spot market, RSPA/OPS believes the proposed regulation will not significantly impact the overall energy supply, distribution, and use.

Unfunded Mandates

This proposed rule does impose unfunded mandates under the Unfunded Mandates Reform Act of 1995, because it may result in the expenditure by the private sector of 100 million or more in any one year. The cost-benefit analysis estimating yearly cost for operators to meet the proposed rule requirements has been placed in the docket. State regulators have participated in our meetings with the industry and research institutions on various integrity management issue discussions and have provided recommendations during our meetings and conference calls. We believe it is the least burdensome alternative that achieves the objective of the rule, because it gives options to industry on how to implement the rule.

National Environmental Policy Act

We have evaluated the proposed rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*) and have preliminarily concluded that this action would not significantly affect the quality of the human environment. The Environmental Assessment determined that the combined impacts of the baseline assessment (pressure testing, internal inspection, or direct assessment), the periodic reassessments, and the additional preventive and mitigative measures that may be implemented for gas pipeline segments that could affect high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures near high consequence areas is likely to be reduced. However, from a national perspective, the impact is not expected to be significant.

Although the effects of the proposed rule will likely lead to fewer incidents, gas pipeline leaks that lead to adverse environmental impacts are rare under current conditions. Although the damage from failures could be reduced, the environmental damage resulting from gas pipeline failures is usually minor under current conditions. The effects are typically negligible, but can consist of localized, temporary damage to the environment in the immediate vicinity of the failure location on the pipeline.

Some operators covered by the proposed rule already have integrity assessment programs. These operators typically consider the pipeline's proximity to populated areas when making decisions about where and when to inspect and test pipelines. As a result, some pipeline segments that could impact high consequence areas have already been recently assessed, and others would be assessed in the next several years without the provisions of the proposed rule. The primary effect of the proposed rule—accelerating integrity assessment in some high consequence areas—shifts increased integrity assurance forward for a few years for some segments that could affect high consequence areas. Because pipeline failure rates are low, shifting the time at which these segments are assessed forward by a few years has only a small effect on the likelihood of pipeline failure in these locations.

The proposed rule does require operators to conduct an integrated assessment of the potential threats to pipeline integrity, and to consider additional preventive and mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause, these assessments should result in additional risk controls to address these threats. However, without knowing the specific high consequence area locations, the specific risks present at these locations, and the existing operator risk controls (including those that surpass the current minimum regulatory requirements), it is difficult to determine the impact of this requirement.

Some gas pipeline operators already perform integrity evaluations or risk assessments that consider the environmental and population impacts. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. For many segments, it is probable that operators will determine that the existing preventive and mitigative activities provide adequate protection to high consequence areas, and that the small additional risk reduction benefits of additional risk controls are not justified.

The primary benefit of the proposed rule will be to establish requirements for conducting integrity assessments and periodic evaluations of integrity of segments that could impact high consequence areas. This will codify the integrity management programs and assessments operators are currently implementing. It will also require other operators, who have little, or no, integrity assessment and evaluation programs to raise their level of performance. Thus, the proposed rule is expected to ensure a more consistent, and overall higher level of protection for high consequence areas across the industry.

The Environmental Assessment of this proposed rule is available for review in the docket.

List of Subjects in 49 CFR Part 192

High consequence areas, potential impact areas, pipeline safety, and record-keeping requirements.

In consideration of the foregoing, RSPA/OPS proposes to amend part 192 of title 49 of the Code of Federal Regulations as follows:

PART 192—[AMENDED]

1. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, and 60118; and 49 CFR 1.53.

2. In subpart M, under the undesignated centerheading ''High Consequence Areas,'' in § 192.761, in the definition beginning ''A high consequence area,'' the word ''A'' is removed, paragraphs (a) and (b) are revised, paragraph (g) is added, and new definitions of Confirmatory direct assessment, Direct assessment, Moderate risk area, Potential impact circle, Potential impact radius, Potential impact zone, and Threshold radius are added alphabetically to read as follows:

§ 192.761 Definitions.

The following definitions apply to this section and § 192.763:

Confirmatory direct assessment is a streamlined integrity assessment method that utilizes process steps similar to direct assessment to evaluate for the presence of corrosion and third party damage.

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to a pipeline's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

High consequence area means any of the following areas:

(a) An area defined as a Class 3 location under § 192.5, except for an area within the class 3 location defined as a moderate risk area.

(b) An area defined as a Class 4 location under § 192.5, except for an area with the class 4 area defined as a moderate risk area.

(c) * * *

(d) * * *

(e) * * *

(f) * * *

(g) An area of a circle of threshold radius 1000 feet or larger that has a cluster of 20 or more buildings intended for human occupancy. The threshold radius is measured from the centerline of the pipeline to the nearest building in the cluster.

Moderate risk area means an area located within a Class 3 or Class 4 location, but not within the potential impact zone.

Potential impact circle is a circle of radius equal to the threshold radius and is used to establish the higher priority area within a Class 3 or 4 area of a high consequence area. A potential impact circle contains any of the following within its radius (refer to the diagram in Appendix E):

(1) Twenty or more buildings intended for human occupancy within a 1000-foot or larger circle of radius;

(2) A facility that is occupied by persons who are hard to evacuate as defined in § 192.761 no matter the size of the circle of radius; or

(3) A place where people congregate as defined in § 192.761, no matter the size of the circle of radius.

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69 * (square root of (p*d2)), where ''r'' is the radius of a circular area surrounding the point of failure (ft), ''p'' is the maximum allowable operating pressure (MAOP) in the pipeline segment (psi) and ''d'' is the diameter of the pipeline (inches). **Note:** 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use Section 3.2 of ASME/ANSI B31.8S to calculate the impact radius formula.

(See Appendix A to this part 192 for incorporation by reference and availability information.)

Potential impact zone is a rectangular area along the pipeline derived from the potential impact circle. The potential impact zone extends axially along the length of the pipeline from the center of the first potential impact circle to the center of the last contiguous potential impact circle, and extends perpendicular to the pipe out to the threshold radius on either side of the centerline of the pipe. (Refer to the diagram in Appendix E).

Threshold radius is an additional area of safety beyond the distance calculated as the potential impact radius. If the calculated potential impact radius is less than 300 feet, the operator must use a threshold radius of 300 feet. If the calculated potential impact radius exceeds 300 feet but is less than 660 feet, the threshold radius is 660 feet. If the calculated potential impact radius exceeds 660 feet, but is less than 1000 feet, the threshold radius is 1000 feet. And, if the calculated potential impact radius exceeds 1000 feet, the threshold radius is 15% greater than the actual calculated impact radius.

3. A new § 192.763 is added under a new undesignated centerheading of ''Pipeline Integrity Management'', in subpart M to read as follows:

Pipeline Integrity Management

§ 192.763 Pipeline integrity management in high consequence areas.

(a) *Which operators must comply?*

This section applies to each operator who owns or operates a transmission line that transports gas, including, petroleum gas, hydrogen, or other gas product covered under this part.

(b) *Which pipeline segments are covered?*

Transmission pipeline segments as defined in § 192.3 that are in a high consequence area, as defined in § 192.761.

(c) *What must an operator do?*

(1) *General requirements.* No later than [one year from the effective date of the final rule], an operator must develop and follow a written integrity management program that addresses the risks on each pipeline segment covered by this section. An operator must—

(i) Identify all high consequence areas as defined in § 192.761, and identify the potential impact zone within each high consequence area. Based on the identification of the potential impact zone within Class 3 and Class 4 locations, identify all moderate risk areas. The identification must include the calculation used in determining the threshold radius for each covered pipeline segment, and any process and factors used in determining the potential impact zone.

(ii) Develop a framework addressing each element required to be in an integrity management program, that includes a plan for baseline assessment of the line pipe (see paragraphs (e) and (g) of this section), and a plan for continual integrity assessment and evaluation (see paragraphs (d) and (k) of this section). The framework must document how decisions will initially be made to implement each program element, and planned near-term improvements to program elements and decision processes.

(iii) Develop a plan that describes how the operator will use direct assessment as part of its integrity assessment (see paragraph (h) of this section), to include identification of External Corrosion Direct Assessment Regions and Internal Corrosion Direct Assessment Regions. This requirement only applies to an operator that plans to use direct assessment.

(iv) Develop a process for continual improvement of the framework into an ongoing integrity management program.

(2) *Time period.* An operator must complete the requirements of paragraph (c)(1) no later than [12 months from the effective date of the final rule].

(3) *Implementation.* An operator must implement and follow the program it develops. In carrying out this section, an operator must follow the requirements of this section and of ASME/ANSI B31.8S, and its appendices, where specified. (*See* Appendix A to this part 192 for incorporation by reference and availability information.) An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this section and ASME/ANSI B31.8S, the requirements in this section control.

(4) *Program changes.* An operator must document, prior to implementing any change to its program, any change to the program and reasons for the change. In addition, an operator must notify OPS in accordance with paragraph (n) of this section of any change to the program that substantially affect the program's implementation or significantly modifies the program or schedule for carrying out the program elements. An operator must provide the notification within 30 days after adopting this type of change into its program.

(5) *Performance-based option.* ASME/ANSI B31.8S provides the essential features of both a performance-based and a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements in paragraph (c)(5)(i) may deviate from certain requirements in this section, as provided in paragraph (c)(5)(ii).

(i) *Exceptional performance.* To deviate from any of the requirements set forth in paragraph (c)(5)(ii), an operator must have completed a baseline assessment of all pipeline segments covered by this section, in accordance with paragraph (g) of this section, and at least one other assessment. An operator must remediate all anomalies identified in the second assessment according to the requirements in paragraph (i), and incorporate the results and lessons learned from the second assessment into the operator's risk model. An operator must also demonstrate that it has an exceptional integrity management program that meets the performance-based requirements of ASME/ANSI B31.8S, has a history of measurable performance improvement, and includes, at minimum—

(A) A state-of-the-art process for risk analysis;

(B) All risk factor data used to support the program;

(C) A state-of-the-art data integration process;

(D) A process that applies lessons learned from assessment of covered pipe segments to pipe segments not covered by this section;

(E) A process for evaluating all incidents, including their causes, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(F) A performance matrix that confirms the continuing performance improvement realized under the performance-based program;

(G) A set of performance measures beyond those required in paragraph (l) of this section that are part of the operator's performance plan (see paragraph (d)(1)(viii)) and are made accessible in real time to OPS and state pipeline safety enforcement officials;

(H) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all pipe segments.

(ii) *Deviation.* Once an operator has demonstrated that it has satisfied the requirements of paragraph (c)(5)(i), the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this section only in the following instances.

(A) The time frame for reassessment as provided in paragraph (k), except that reassessment by some method (*e.g.*, confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(B) Direct assessment as a primary assessment method without having to meet the conditions specified in paragraph (h)(1); and

(C) The time frame for remediation as provided in paragraph (i).

(d) *What are the elements of an integrity management program?*

(1) *General.* An operator's initial integrity management program framework and subsequent integrity management program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S for more detailed information on the listed element.)

(i) An identification of covered pipeline segments and the potential impact zone for each segment. An identification includes a calculation of the potential impact radius and threshold radius for each segment.

(ii) A baseline assessment plan meeting the requirements of paragraphs (e) and (g) of this section.

(iii) An identification of threats to each covered pipeline segment, which includes a risk assessment to evaluate the failure likelihood of each covered segment. An operator will use the threat identification and risk assessment to prioritize segments for assessment (paragraphs (g) and (k)) and evaluate the merits of additional preventive and mitigative measures (paragraph (j)). The identification and risk assessment process must comply with the requirements in paragraph (f) of this section.

(iv) A direct assessment plan, if applicable, meeting the requirements of paragraph (h) of this section.

(v) Provisions meeting the requirements of paragraph (i) of this section for remediating conditions found during an integrity assessment.

(vi) A process for continual evaluation and assessment meeting the requirements of paragraphs (h)(6) and (k) of this section. If applicable, the process must include a plan for confirmatory direct assessment meeting the requirements of paragraph (h)(6).

(vii) Preventive and mitigative measures meeting the requirements of paragraph (j) of this section.

(viii) A performance plan as outlined in ASME/ANSI B31.8S, Section 9 that includes performance measures meeting the requirements of paragraph (l) of this section.

(ix) Record keeping requirements meeting the requirements of paragraph (m) of this section.

(x) A management of change process as outlined in ASME/ANSI B31.8S, Section 11.

(xi) A quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.

(xii) A communication plan that includes the elements of ASME/ANSI B31.8S, Section 10, and that includes a process for addressing safety concerns raised by OPS, including safety concerns OPS raises on behalf of a State or local authority with which OPS has an interstate agent agreement.

(xiii) A process for providing, by electronic or other means, a copy of the operator's integrity management program to a State authority with which OPS has an interstate agent agreement.

(xiv) A process for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

(2) *Training.* (i) *Supervisory personnel.* An operator's integrity management program must provide that each supervisor possesses and maintains a thorough knowledge of the operator's integrity management program and the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(ii) *Persons who evaluate.* An operator's integrity management program must provide criteria for the qualification of persons who review and analyze results from integrity assessments and evaluations. These criteria include criteria for persons who carry out and interpret the results from the direct assessment process.

(3) *Newly-identified areas.* The program must provide for identification and assessment of newly-identified high consequence areas. When an operator has information that the area around a pipeline segment satisfies any of the definitions for high consequence areas in § 192.761, the operator must incorporate the area into its integrity management program within one year from the date the area is identified.

(e) *What must be in the baseline assessment plan?* An operator must include each of the following elements in its written baseline assessment plan:

(1) Identification of the potential threats to each of the covered pipeline segments. (See paragraph (f) of this section);

(2) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the segment (see paragraph (f) of this section). More than one method may be required to address all the threats to the pipeline segment;

(3) A schedule for completing the integrity assessment of all covered line segments, including, risk factors considered in establishing the assessment schedule;

(4) If applicable, a direct assessment plan that meets the requirements of paragraph (h) of this section.

(5) A process describing how the operator is ensuring that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

(f) *How does an operator identify potential threats to pipeline integrity?*

(1) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S , section 2 and the following:

(i) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(ii) Static or resident threats, such as fabrication or construction defects;

(iii) Time independent threats such as third party damage and outside force damage; and

(iv) Human error.

(2) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix SP–A to ASME/ANSI B31.8S, and consider both on the covered segment and similar segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and all other conditions specific to each pipeline.

(3) *Risk assessment.* An operator is to conduct a risk assessment on each covered segment that follows ASME/ANSI B31.8S, section 5, and uses the threats identified for each segment. An operator will use the risk assessment to prioritize the segments for the baseline

and continual re-assessments (paragraphs (e), (g) and (k) of this section), and in determining what additional preventive and mitigative measures are needed (paragraph (j) of this section).

(g) *How is the baseline assessment to be conducted?*

(1) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the segment (*See* paragraph (f) of this section).

(i) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the pipe segment is susceptible. An operator must follow ASME/ANSI B31.8S in selecting the appropriate internal inspection tools.

(ii) Pressure test conducted in accordance with subpart J of this part;

(iii) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with ASME/ANSI B31.8S and paragraph (h) of this section;

(iv) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with paragraph (n) of this section.

(2) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each segment. The risk analysis must comply with the requirements in paragraph (f) of this section.

(3) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment, an operator must take the following actions to address particular threats that it has identified. (*See* paragraph (f) of this section).

(i) *Third party damage.* An operator must address the third party damage threat through the following:

(A) *Preventive measures.* An operator must implement comprehensive additional preventive measures (*see* paragraph (j)) to address the threat, and monitor the effectiveness of the preventive measures.

(B) *Assessment tools.* An operator must assess covered segments that are vulnerable to delayed failure following third party damage using internal inspection tools, such as deformation or geometry tools. An operator may use direct assessment as the primary assessment method for third party damage only if no other approach is feasible, and it is combined with data collection and integration to evaluate segment susceptibility to third party damage. An operator that does not use a geometry tool for the internal inspection or uses direct assessment must excavate and directly examine all indications that could be the result of third party damage.

(ii) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) necessitates a periodic assessment for dents and gouges. An evaluation must assume the presence of deep dents, and determine whether loading conditions would lead to failure of such hypothesized dents. An operator must use the results from an evaluation together with the criteria used to evaluate the significance of this threat.

(iii) *Manufacturing and construction defects.* To address manufacturing and construction defects (including seam defects), an operator must perform a pressure test at least once in the life of the segment unless the operator demonstrates why pressure testing is not necessary to address this threat. If an operator does not perform a pressure test, and at anytime the historic operating pressure or other stress condition changes, including any condition that affects cyclic fatigue, the operator must, prior to changing the stress condition, assess the pipeline using an assessment method allowed by this section.

(iv) *ERW pipe.* The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to seam failures must be capable of assessing seam integrity and of detecting seam corrosion anomalies.

(v) *Corrosion.* If an operator finds corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in paragraph (i)), the operator must conduct an integrity assessment and remediate all pipeline segments with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.

(4) *Time period.* An operator must comply with the following requirements in conducting the baseline assessment of the covered segments.

(i) *Internal inspection or pressure test.* An operator that uses an internal inspection tool or pressure test as an integrity assessment method must comply with the following time periods for conducting the assessment.

(A) Unless the exception in paragraph (g)(4)(i)(B) of this section applies, an operator using a pressure test or internal inspection tool as an assessment method must complete the baseline assessment by December 17, 2012. An operator must assess at least 50% of the line pipe being assessed by either of these methods beginning with the highest risk pipe, by December 17, 2007. An operator must prioritize segments for assessment in accordance with paragraphs (f)(3) and (g)(2) of this section, giving highest priority to those segments located in the potential impact zone (refer to Appendix E for guidance).

(B) An operator using a pressure test or internal inspection tool as an assessment method on a pipeline segment located in a moderate risk area (an area within a Class 3 or Class 4 location, but not within the potential impact zone), must complete the baseline assessment by December 17, 2015.

(ii) *Direct assessment.* An operator that uses direct assessment as an integrity assessment method must comply with the following time periods for conducting the assessment.

(A) Unless the exception in paragraph (g)(4)(ii)(B) applies, an operator using direct assessment as an assessment method must complete the baseline assessment by December 17, 2009. An operator must assess at least 50% of the line pipe being assessed by this method, beginning with the highest risk pipe, by December 17, 2006. Direct assessment must be carried out in accordance with paragraph (h) of this section. An operator must prioritize segments for assessment in accordance with paragraphs (f)(3) and (g)(2) of this section, giving highest priority to those segments located in the potential impact zone (refer to Appendix E for guidance).

(B) An operator using direct assessment as an assessment method on a pipeline segment located within a moderate risk area (area in a Class 3 or Class 4 location, but not within the potential impact zone), must complete the baseline assessment of the line pipe being assessed by this method by December 17, 2012.

(5) *Prior assessment.* An operator may use an integrity assessment conducted after December 17, 2007 as a baseline assessment, if the integrity assessment method meets the requirements of this

section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to the requirements of paragraph (k) of this section.

(6) *Newly identified areas.* When the operator has information that the area around a pipeline segment satisfies any of the definitions in § 192.761, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe in the newly identified high consequence area within 10 years (7 years if direct assessment is being used) from the date the area is identified.

(h) *When can direct assessment be used and under what conditions?*

(1) *General.* (i) An operator may use direct assessment as a supplement to the other assessment methods allowed under this section. However, an operator may use direct assessment as a primary assessment method for external corrosion, internal corrosion, or stress corrosion cracking only when the operator can demonstrate one of the following conditions applies—

(A) The operator demonstrates that other assessment methods allowed under this section can not be applied to the pipeline segment for economic or technological reasons;

(B) The operator demonstrates that other assessment methods allowed under this section would result in a substantial impact on gas customers, as for example, when only one pipeline delivers gas to homes or local businesses, and service would be completely shut down during the assessment;

(C) The operator will excavate and conduct a direct examination of the entire covered pipeline segment in accordance with the requirements of this paragraph; or

(D) The covered pipeline segment operates at a maximum allowable operating pressure below 30% SMYS.

(ii) An operator using direct assessment as a supplemental assessment method must have a plan that follows the requirements for confirmatory direct assessment in paragraph (h)(6) of this section. An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements for use of direct assessment in ASME/ANSI B31.8S, section 6.4 and in this section.

(2) *Specific threats.* An operator may only use direct assessment as a primary assessment method for external corrosion, internal corrosion, and stress corrosion cracking. An operator may use direct assessment as the primary assessment method for third party damage only if no other assessment method is feasible, and the operator uses it in combination with data collection and integration to evaluate the segment's susceptibility to third party damage.

(3) *External corrosion direct assessment (ECDA).* An operator that uses direct assessment as the primary method to assess external corrosion must follow the requirements in this section and in ASME/ANSI B31.8S, Section 6 and Appendix SP–B.

(i) *ECDA plan.* An operator using External Corrosion Direct Assessment (ECDA) must prepare a plan that includes—

(A) A process that provides, according to the requirements of this paragraph, for Pre-Assessment, Indirect Examination, Direct Examination, and Post-Assessment.

(B) Data requirements for using ECDA. These must, at a minimum, include the data requirements for external corrosion specified in Appendix SP–A1 to ASME/ANSI B31.8S.

(C) Criteria for evaluating ECDA feasibility, in accordance with paragraph (h)(3)(ii)(A) of this section.

(D) Criteria for defining ECDA Regions, in accordance with paragraph (h)(3)(ii)(B) of this section.

(E) The basis on which an operator selects two complementary assessment tools to assess each ECDA Region. Guidance on selecting tools is found in Appendix E of this part.

(F) Criteria for identifying and documenting those indications that must be considered for direct examination. Minimum criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected.

(G) Criteria for characterizing indications identified in the ECDA process. These criteria must define how an operator will characterize an indication as severe, moderate or minor (*See* paragraph (h)(3)(iv) of this section).

(H) Criteria for defining the urgency of excavation and direct examination of each indication. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored. Monitored indications are defects that are not serious and may or may not require direct examination.

(I) Criteria for scheduling excavation of each urgency level of indication, in accordance with paragraph (h)(3)(v) of this section.

(J) Criteria for data gathering associated with each excavation.

(K) Criteria for the qualification of persons who carry out and interpret the results from the direct assessment process (*See* paragraph (d)(2)(ii) of this section).

(L) Criteria and measures for evaluating the long-term effectiveness of the ECDA process (*See* paragraph (h)(3)(vii) of this section).

(ii) *Pre-assessment.* An operator using ECDA must conduct a pre-assessment, in which the operator analyzes and integrates the data and information required in paragraph (f) of this section to carry out the following—

(A) *Feasibility.* An operator will use the data to determine whether any of the following conditions exists that is likely to preclude the effective use of ECDA. If any of the listed conditions is present, the operator must demonstrate why the use of ECDA would be a more effective method to assess external corrosion than the other assessment methods allowed under this section and specify the provisions the operator will implement to ensure ECDA effectiveness.

(*1*) The presence of a coating that causes electrical shielding;

(*2*) Backfill around the pipe with significant rock content or the presence of rock ledges;

(*3*) Situations impeding timely above-ground data gathering;

(*4*) Locations with adjacent buried metallic structures;

(*5*) Inaccessible areas.

(B) *ECDA Region.* An operator must use the data gathered to define all ECDA regions within the covered pipeline segment. ECDA regions are those portions within a pipeline segment, not necessarily contiguous, that have similar physical characteristics, operating and corrosion history, expected future corrosion conditions, and which are suitable for the same indirect assessment methods. An operator may redefine ECDA regions at any time the information the operator develops in conducting justifies a redefinition. If a condition, such as those specified in paragraph (h)(3)(vi)(C) of this section, exists for which ECDA is ineffective at assessing, an operator must select an alternate assessment technology allowed under this section.

(iii) *Indirect examination.* An operator's ECDA plan must provide for indirect examination of the ECDA regions. In carrying out the indirect examination, an operator must follow ASME/ANSI B31.8S, Appendix SP–B2 and the requirements of this section.

(A) Unless the exception in paragraph (h)(3)(iii)(B) of this section applies, an operator must select at least two different, but complementary, indirect examination methods, for each location where ECDA is to be applied along the pipeline segment. An operator must select the methods that can best detect external corrosion activity and holidays in the pipe coating under the conditions the operator expects to find on the pipeline. (Appendix E gives guidance on selecting two complementary methods). Indirect examination methods include, but are not limited to, Close Interval Surveys (CIS), Direct (or Alternate) Current Voltage Gradient (DCVG or ACVG), and electromagnetic techniques, such as Pipeline Current Mapper (PCM), and C-Scan). An operator must perform the indirect examination using the complementary methods selected for each ECDA Region. An operator must define the boundaries for use of each pair of ECDA tools, and ensure complete coverage through overlap between adjacent ECDA regions.

(B) If one of the following conditions applies, an operator must use one indirect examination tool and one alternative (*e.g.* ultrasonic) tool to assess for external corrosion, unless the operator demonstrates that one method will be adequate to assure the integrity of the segment being assessed for external corrosion.

(*1*) Pipe in frozen ground;

(*2*) Pipe under paved roadways;

(*3*) Pipe in cased crossings (either road or river).

(C) An operator must also provide for the following in its indirect examination.

(*1*) Repeating indirect examination methods on a sample basis to ensure consistent data are obtained;

(*2*) Selecting intervals for capturing tool readings that are closely spaced enough to ensure consistent data are obtained. Data sampling intervals (locations of test points) for indirect examination methods should typically be no greater than the local depth of coverage of the pipeline;.

(*3*) Carrying out indirect examination in an ECDA Region using the two complementary tools as close together in time as practical;

(*4*) Geo-referencing above ground measurements to compare examination results and accurately identify excavation locations.

(iv) *Post-indirect examination.* After an operator completes its indirect examination measurements for an ECDA Region, the operator must align the measures with the complementary tools and evaluate the consistency of the observations.

(A) If the results from the two complementary tools are not consistent and cannot be explained by differences in the tools' capabilities, the operator must either conduct a direct examination or additional indirect examinations to evaluate the reasons for the differences.

(B) If additional indirect inspections or direct examinations are not carried out or if they do not resolve the inconsistencies, the operator must re-evaluate the feasibility of ECDA.

(C) An operator must identify and locate indications following the indirect inspection, and classify the severity of each indication as severe, moderate or minor using the criteria in the ECDA Plan. (See paragraph (h)(3)(i) of this section). These classifications must be conservatively developed the first time the process is applied.

(D) An operator must compare the results from the pre-assessment step with the prior history for each ECDA Region. If assessment results are not consistent with operating history, the operator must reassess the feasibility of ECDA.

(v) *Direct examination.* An operator's ECDA plan must include a process for using the results from the indirect examination to develop and carry out a direct examination plan. A direct examination includes an excavation to confirm the ability of the indirect examination to locate external corrosion. To carry out the direct examination an operator must—

(A) Determine the order and timing of excavations from results of the indirect examination integrated with the risk factor data. An operator must base both order and timing on a classification of the indications as immediate action, scheduled action or monitored action. (See paragraph (h)(3)(i) of this section).

(B) Make a direct examination (excavation) of all indications that meet the criteria for immediate action. An operator must excavate all immediate action indications promptly, but no later than six months after completing the indirect examination. If an operator finds any evidence of severe corrosion in an ECDA region, the operator must evaluate the entire covered segment and all other covered and non-covered segments in the operator's pipeline system with similar characteristics, for corrosion, and take appropriate action for that segment, which could include an integrity assessment, remediation, or additional preventive or mitigative measures.

(C) Make a direct examination of at least two of the highest risk indications in each ECDA Region that meet the criteria of scheduled action. An operator must excavate each scheduled action indication in order of priority, until the operator excavates at least two indications that have a corrosion of depth no greater than 20% of the wall thickness.

(D) Make a direct examination of at least one of the highest risk indications in an ECDA region that contains only monitored indications.

(E) Make a minimum of one direct examination in each ECDA Region. This examination must be made at the indication of highest risk. If no indications are shown in the ECDA Region, then the excavation must be made at a location that the operator considers to be the most suspect.

(vi) *Remediation.* Except for conditions specified in paragraph (i)(4) of this section, an operator must remediate indications found during the direct assessment according to the requirements in ASME/ANSI B31.8S, section 7. Remediation must be consistent with a determination of remaining strength using ASME B31G or RSTRENG. (*See* Appendix A to this part 192 for incorporation by reference and availability information). If an operator finds an indication is associated with a defect that requires immediate remediation, the operator must reduce operating pressure by at least 20% in the associated ECDA Region and not increase this pressure until the operator has excavated, evaluated and remediated, as necessary, 100% of such indications within the region. In remediating a condition, an operator must also comply with the following—

(A) If any exposed segment has significant coating degradation or corrosion, the operator must increase the size of that excavation until coating and pipe are determined to be adequate.

(B) The operator must identify the root cause of all significant corrosion activity revealed by excavation.

(C) When an operator identifies any defect in an ECDA Region that requires immediate mitigation, or determines that the root cause of any defect is a condition that ECDA is ineffective at assessing (*e.g.*, MIC or shielded corrosion), the operator must for the current assessment cycle reassess the entire ECDA Region, using an alternative assessment method allowed by this section.

(vii) *Post-Assessment.* An operator must determine the reassessment interval for the pipeline segment and evaluate the overall effectiveness of the ECDA process.

(A) *Reassessment.* An operator must determine the reassessment interval according to the requirements in paragraph (k)(3) of this section.

(B) *Performance measures.* An operator must define and monitor measures to determine the effectiveness of the ECDA process. At minimum, these measures must track—

(*1*) The effectiveness of the overall process (*e.g.*, the change in the calculated reassessment interval);

(*2*) The extent and severity of corrosion found;

(*3*) The number of indications in each classification located on successive applications of ECDA; and

(*4*) The time from discovery of an indication categorized as immediate action or scheduled action to its excavation.

(4) *Internal corrosion direct assessment (ICDA).* ICDA is a process that identifies areas along the pipeline where water or other electrolyte introduced by an upset condition may reside, then focuses direct examination on the locations in each area where internal corrosion is most likely to exist. An operator using direct assessment as an assessment method to address internal corrosion in a pipeline segment must follow the requirements in ASME/ANSI B31.8S, Appendix SP–B2, and in this section.

(i) *ICDA plan.* An operator that uses direct assessment to assess internal corrosion must prepare a plan that, at minimum, provides for the following—

(A) A process for data gathering to evaluate the potential for internal corrosion, and to support pre-assessment in accordance with paragraph (h)(4) (ii) (A) of this section;

(B) Identification of ICDA Regions, in accordance with paragraph (h)(4)(ii)(B) of this section;

(C) Identification of excavation locations and direct examination of the locations in accordance with paragraphs (h)(4)(ii)(C) and (h)(4)(ii)(D) of this section;

(D) Post assessment and continuing evaluation in accordance with paragraph (h)(4)(ii)(E).

(ii) *Corrosion identification.* An operator must have a process to evaluate the potential for internal corrosion caused by water, CO_2, O_2, chlorides, hydrogen sulfide and other contaminants present in the gas, and for MIC. This process must, in accordance with the requirements of this paragraph, provide for pre-assessment, identification of ICDA regions and excavation locations, direct examination and post assessment.

(A) *Pre-assessment.* An operator must gather information needed to identify areas along the covered pipeline segment where internal corrosion is most likely to exist. An operator will use this information to identify the locations where water may accumulate, to identify ICDA regions, and to support the flow model. This information includes, but is not limited to—

(*1*) All data elements listed in Appendix SP–A2 of ASME/ANSI B31.8S.

(*2*) Information needed to support a flow model that an operator uses to determine areas along the pipeline where internal corrosion is most likely to occur. This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on the line such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline.

(*3*) Operating experience data that would provide an indication of historic upsets in gas conditions, locations where these upsets have occurred, and any indications of damage resulting from these upset conditions.

(B) *Identification of ICDA regions.* An operator must define all ICDA Regions within each covered pipeline segment. An ICDA region extends from the location where water may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and further evaluation is needed. To identify ICDA regions, an operator must apply the results of a mathematical flow model that defines the critical pipe incline above which water film cannot be transported by the gas. This flow model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce moisture) and locations downstream of gas draw-offs (gas velocity is reduced). Graph E.III.A in Appendix E of this Part provides the flow model.

(C) *Identification of excavation locations.* After identifying the ICDA regions, an operator must then identify for excavation the most likely locations for internal corrosion in each region. An operator must identify a minimum of two locations for excavation in each ICDA Region. One location must be the low point (*e.g.*, sags, drips, valves, manifolds, dead-legs, traps) nearest to the beginning of the ICDA Region. The second location must be at the upstream end of the pipe incline nearest the end of the ICDA Region.

(D) *Direct examination.* An operator must, at a minimum, excavate in each ICDA Region the two locations identified for excavation in paragraph (h)(4)(ii)(C), and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements. If corrosion exists at either location, the operator must—

(*1*) Remediate the conditions it finds in accordance with paragraph (i) of this section;

(*2*) As part of the operator's current integrity assessment either perform additional excavations in the ICDA region or use an alternative assessment method allowed by this section to assess the pipe for internal corrosion; and

(*3*) Evaluate all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to those in which the corrosion was found, and remediate the conditions it finds in accordance with paragraph (i) of this section.

(E) *Post Assessment and Continuing Evaluation.* An operator must continually monitor each covered segment where internal corrosion has been identified using techniques such as coupons or electronic probes. An operator must also periodically draw off fluids at low points and chemically analyze the fluids for the presence of corrosion products. The frequency of the monitoring and fluid analysis must be based on results from past and present integrity assessment results and risk factors specific to that pipeline. If an operator finds any evidence of corrosion products the operator must, either—

(*1*) *conduct excavations at locations downstream where moisture might accumulate;* or

(*2*) assess the segment using another integrity assessment method allowed by this section, and remediate the conditions it finds in accordance with paragraph (i) of this section. The interval for re-assessing the segment with another assessment method must not exceed the time frames specified in paragraph (k)(3)(ii) of this section.

(5) *Stress Corrosion Cracking (SCC).* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking must develop and follow a plan that provides for—

(i) Development and implementation of a systematic SCC data collection and evaluation process for all segments to identify if the conditions for SCC are present and to prioritize the segments for assessment. An operator may refer to ASME/ANSI B31.8S, Appendix SP–A3 for identifying the threat of SCC. This process must include gathering and evaluating data related to SCC at all excavation sites where the criteria indicate the potential for SCC. This data includes at minimum, the data specified

in ASME/ANSI B31.8S, Appendix SP–A3.

(ii) Selection and implementation of an integrity assessment method and remediation of the threat, if conditions for SCC are identified. An operator must use the bell hole examination and evaluation technique to assess SCC, as specified in ASME/ANSI B31.8S, Appendix SP–A3.

(6) *Confirmatory direct assessment.* An operator using the confirmatory direct assessment method as allowed in paragraph (k)(3) of this section must have a plan that meets the following requirements:

(i) *Threats.* For any covered segment on which confirmatory direct assessment is used, the focus must be on identifying damage resulting from external corrosion, internal corrosion and third party damage.

(ii) *External corrosion plan.* An operator's plan for confirmatory direct assessment for identifying external corrosion must includes processes for pre-assessment, indirect examination, direct examination and remediation.

(A) The pre-assessment must follow the requirements in paragraph (h)(3)(ii) of this section, and include identification of External Corrosion Direct Assessment (ECDA) regions.

(B) The indirect examination must follow the requirements in paragraph (h)(3)(iii) of this section, except that the examination may be conducted using only one indirect examination tool suitable for the application.

(C) The direct examination must follow the requirements in paragraph (h)(3)(v) of this section with the following exceptions—

(*1*) Excavation of all immediate action indications is required in each ECDA region;

(*2*) Excavation of at least one high risk indication that meets the criteria of scheduled action is required in each ECDA region; and

(*3*) No excavation is required for indications categorized as monitored indications.

(D) The remediation must follow the requirements in paragraph (h)(3)(vi) of this section.

(iii) *Internal Corrosion plan.* An operator's plan for confirmatory direct assessment for identifying internal corrosion must include processes for pre-assessment, identification of Internal Corrosion Direct Assessment (ICDA) Regions, identification of excavation locations, direct examination and remediation.

(A) The pre-assessment must follow the requirements in paragraph (h)(4)(ii)(A) of this section.

(B) The identification of ICDA Regions must follow the requirements in paragraph (h)(4)(ii)(B) of this section.

(C) The identification of excavation locations and excavation must follow the requirements in paragraph (h)(4)(ii)(C) of this section, except that the operator must identify for excavation at least one high risk location in each ICDA Region.

(D) The direct examination (excavation) and remediation must follow the requirements in paragraph (h)(4)(ii)(D) of this section, except that the operator is to choose one high risk location in each ICDA Region for excavation.

(iv) *Third party damage.* An operator's plan for confirmatory direct assessment for identifying third party damage must include identification of pipeline segments where construction or other groundbreaking activity was reported near the pipeline right-of-way since the previous assessment. The confirmatory direct assessment for third part damage must follow the requirements in paragraph (g)(3)(i) of this section.

(i) *What actions must be taken to address integrity issues?*

(1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. If an operator is unable to respond within the time limits for certain conditions specified below, the operator must temporarily reduce the operating pressure of the pipeline. An operator must determine the temporary reduction in operating pressure using section 851.42 of ASME/ANSI B31.8 for dents and gouges, ASME/ANSI B31G or RSTRENG for corrosion, or reducing the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (See Appendix A to this part 192 for incorporation by reference and availability information). A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline.

(2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. If the operator cannot make the necessary determination within the 180-day period, an operator must notify OPS of the reasons for the delay and the expected time for obtaining the information.

(3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (h)(3)(vii) or paragraph (i)(4) of this section, an operator must follow the schedule in ASME/ANSI B31.8S. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with paragraph (n) of this section if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure.

(4) *Special requirements for scheduling remediation.*

(i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(A) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than 1.1 times the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G ''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991); AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)); or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in Appendix A to Part 192.

(B) A dent that has any indication of metal loss, cracking or a stress riser.

(C) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(ii) *180-day remediation.* Except for conditions listed in paragraph (i)(4)(i) of this section, an operator must remediate any of the following within 180 days of discovery of the condition:

(A) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(iii) *Remediation longer than 180 days.* An operator may take more than 180 days following discovery of the condition to remediate any of the following conditions unless the anomaly grows to critical stage. If the anomaly grows to critical stage, the operator must follow the immediate repair requirements in paragraph (i)(4)(i) of this section.

(A) In a segment assessed by internal inspection, a calculation of the remaining strength of the pipe shows a predicted failure pressure greater than 1.1 times the established maximum operating pressure at the location of the anomaly. An operator must remediate the condition in accordance with ASME/ANSI B31.8S, Section 7, Figure 7–1.

(B) In a segment assessed by any integrity assessment method, an anomalous condition other than those listed in paragraphs (i)(4)(i) or (ii) of this section.

(j) *What additional preventive and mitigative measures must an operator take to protect the high consequence area?*

(1) *General Requirements.* An operator must take measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator's measures will be based on the threats it has identified to each pipeline segment (see paragraph (f)). These measures include an operator conducting, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S, Section 5, a risk analysis of the covered pipeline segments to identify additional actions to enhance public safety. Such actions include, but are not limited to, installing Automatic Shut-off valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional extensive inspection and maintenance programs.

(2) *Third Party Damage and Outside Force Damage.* An operator must take additional measures to prevent and minimize the consequence of a release from third party damage or outside force damage. These measures must be in addition to any already required under this Part. An operator may follow ASME/ANSI B31.8S, Table 7–1 of Section 7 in identifying these measures. To minimize the consequences from third party damage, including vandalism, measures include, but are not limited to, increasing the frequency of aerial and foot patrols, participating in one-call systems, conducting extensive public education campaigns, increasing marker frequency, increasing cover depth, and adding leakage control measures. To minimize the consequences from outside force damage (*e.g.* earth movement, floods, unstable suspension bridge) these measures include, but are not limited to, increasing the frequency of aerial and foot patrols, adding external protection, reducing external stress, and relocating the line.

(3) *Automatic Shut-off valve (ASV) or Remote Control Valves (RCV).* If an operator determines that an ASV or RCV is needed on a pipeline segment to protect a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(k) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*

(1) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in paragraph (k)(3) and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (k)(2). The reassessment period for a segment begins upon completion of the prior assessment.

(2) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. The periodic evaluation must be based on a data integration of the entire pipeline as specified in paragraph (f) of this section to identify the threats specific to a pipeline segment. The evaluation must consider the past and present integrity assessment results, data integration information (paragraph (f) of this section), and decisions about remediation and preventive and mitigative actions (paragraphs (i) and (j) of this section).

(3) *Re-Assessment intervals.* An operator must establish a re-assessment interval for each covered pipeline segment. An operator must comply with the following requirements in establishing the interval for the operator's covered pipeline segments.

(i) *General.* Unless a period of less than seven years is specified, each covered pipeline segment must be re-assessed at a seven-year interval. If the operator establishes a reassessment interval for the covered segment that is greater than seven years, the operator must within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment. The reassessment done by confirmatory direct assessment must be done in accordance with paragraph (h)(6) of this section.

(ii) *Pressure test or internal inspection, or other equivalent technology.*

(A) An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for covered pipeline segments by—

(*1*) Basing the intervals on the identified threats for the segment as listed in paragraph (f) of this section and in ASME/ANSI B31.8S, Table 8–2, section 8, and on the analysis of the results from the last integrity assessment and from the data integration required by paragraph (f) of this section; or

(*2*) Using the intervals for different stress levels of pipeline specified in ASME/ANSI B31.8S, Table 8–1, section 8.

(B) However, under either option, the maximum reassessment interval must not exceed ten (10) years for a pipeline operating at or above 50% SMYS, and 15 years for a pipeline operating below 50% SMYS. An operator choosing the maximum period allowed for reassessment must demonstrate that it has implemented enhanced preventive and mitigative measures for the segment.

(iii) *Direct assessment.*

(A) An operator that uses direct assessment must determine the reassessment interval according to the following calculation.

(*1*) Determine the largest defect most likely to remain in the segment and the corrosion rate appropriate for the pipe, soil and protection conditions.

(*2*) Take the largest remaining defect as the size of the largest defect discovered in the ECDA or ICDA segment.

(*3) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.*

(B) However, the reassessment interval cannot exceed five (5) years, if an operator directly examines and remediates defects by sampling, or ten (10) years, if an operator conducts a direct examination of all anomalies and remediates these anomalies.

(4) *Waiver from interval greater than 7 years in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval greater than seven years but within the maximum allowable interval if OPS finds a waiver would not be inconsistent with pipeline safety.

(i) *Lack of internal inspection tools.* An operator may be able to justify a longer assessment period for a covered segment if internal inspection tools are not available to assess the line pipe. An operator must demonstrate that the internal inspection tools cannot be obtained within the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must, in accordance with paragraph (n) of this section, notify OPS 180 days before the end of the required reassessment interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed.

(ii) *Maintain local product supply.* An operator may be able to justify a longer assessment period for a covered segment if the operator demonstrates that the reassessment will shut off the local product supply, and that alternative supply is not available. An operator must, in accordance with paragraph (n) of this section, notify OPS 180 days before the end of the required reassessment interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed.

(5) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe by any of the following methods.

(i) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the pipe segment is susceptible. An operator must follow ASME/ANSI B31.8S, section 6.2, in selecting the appropriate internal inspection tools;

(ii) Pressure test conducted in accordance with subpart J of this Part;

(iii) Direct assessment to address threats of external corrosion threats, internal corrosion, and stress corrosion cracking that is conducted in accordance with ASME/ANSI B31.8S section 6.3, and paragraph (h) of this section;

(iv) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with paragraph (n) of this section.

(v) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with paragraph (h)(6) of this section.

(l) *What methods must be used to measure program effectiveness?* (1) *General.* An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S, Section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix SP–A. An operator must make the four overall performance measures accessible in real time to OPS and state pipeline safety enforcement officials.

(2) *Direct assessment.* In addition to the general requirements for performance measures, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of paragraph (h)(3)(vii) of this section.

(m) *What records must be kept?* An operator must maintain for review during an inspection—

(1) A written baseline assessment plan in accordance with paragraphs (e) and (g) of this section;

(2) A written integrity management program in accordance with the requirements of this section.

(3) Documents to support the decisions, analyses and processes developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

(4) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with paragraph (d)(2) of this section.

(5) Documents to carry out the requirements in paragraph (h) of this section for a direct assessment plan.

(6) Documents demonstrating the integrity management program has been provided to the interstate agent, and that any safety concerns raised by OPS on behalf of an interstate agent have been addressed.

(n) *How does an operator notify OPS?* An operator must provide notification required by this section by—

(1) Sending the notification to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW., Washington DC 20590;

(2) Sending the notification by facsimile to (202) 366–7128; or

(3) Entering the information directly on the Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/imdb/.*

3. Appendix A to Part 192, section II.D would be amended by adding paragraph (9) to read as follows:

Appendix A to Part 192—Incorporated by Reference

* * * * *

II. * * *

D. * * *

(9) ASME/ANSI B31.8S 2001 Supplement to B31.8 on Managing System Integrity of Gas Pipelines, January 31, 2002.

4. A new Appendix E to Part 192 would be added to part 192 to read as follows:

Appendix E to Part 192

I. Guidance on Determining a Potential Impact Zone Within a High Consequence Area

Within each high consequence area, an operator is to calculate the potential impact zone. (Refer to figure E.I.1 for the diagram of a potential impact zone) High consequence areas and potential impact zone are defined in § 192.761. The potential impact zone will help an operator determine the area where segments must be given priority for assessment.

The Potential Impact Zone definition (§ 192.761) expands the area protected and provides the basis for prioritizing the pipeline segments for assessment and remediation. The priority an operator is to give each covered segment depends on the population density within the potential impact radius. An operator will need to perform the following—

(1) Identify all high consequence areas;

(2) Calculate the Potential Impact Radius (PIR) for each pipeline segment;

(3) Determine the Threshold Radius associated with the PIR for each segment;

(4) Identify the Potential Impact Circle for each segment;

(5) Identify the Potential Impact Zone for each segment;

(6) Determine the priority of each segment giving higher priority to any segment within a potential impact zone.

II. Guidance on ECDA Tool Selection and Definition of External Corrosion Direct Assessment (ECDA) Regions

This section gives guidance to help an operator implement the requirements for a direct assessment plan in § 192.763 (h). An operator that chooses to use direct assessment to assess the threat of external corrosion on the operator's covered pipeline segments may refer to this guidance for selecting inspection tools to carry out the indirect inspection requirements and for defining external corrosion regions.

A. Selection of Indirect Inspection Tools

The rule (§ 192.763(h)(3)(iii)), requires an operator to select a minimum of two indirect inspection tools for all ECDA locations along the pipeline segment.

- The pipeline operator must select indirect inspection tools based on their ability to reliably detect corrosion activity under the specific pipeline conditions to be encountered.
- The ''indirect inspection tool selection'' column in Table E.II.1 includes items that should be considered when selecting indirect inspection tools.
- Table E.II.2 provides guidance on selecting indirect inspection tools and specifically addresses conditions under which some indirect inspection tools may not be practical or reliable.
- The pipeline operator does not have to use the same indirect inspection tools at all locations along the pipeline segment. Figure E.II.1 demonstrates how the selection of indirect inspection tools may vary along a segment.

B. Identification of ECDA Regions

The rule (§ 192.763(h)(3)(ii)) requires an operator to analyze data it has collected to identify ECDA regions.

- The definition of ECDA regions will evolve through the *Indirect Inspection Step* and the *Direct Examination Step.* An operator is expected to establish a preliminary definition and fine tune it later in the ECDA process.
- The pipeline operator should define criteria for identifying ECDA regions.
- An ECDA region should include locations that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and use the same indirect inspection tools.
- The pipeline operator should consider physical characteristics, soil conditions, and corrosion protection mechanisms that the pipeline operator considers significant in affecting external corrosion when defining criteria for identifying ECDA regions. Table E.1 may be used as guidance in establishing ECDA regions.
- A single ECDA region does not need to be contiguous. That is, an ECDA region may be broken along the pipeline, for example, if similar conditions are encountered on either side of a river crossing.
- An operator should include the entire pipeline segment in an ECDA region.
- Figure E.II.2 gives an example definition of ECDA regions for a given pipeline.
- A pipeline operator should define five distinct areas based on soil characteristics and previous history.
- Based on the choice of indirect inspection tools, the soil characteristics, and the previous history, the pipeline operator should define seven ECDA regions.

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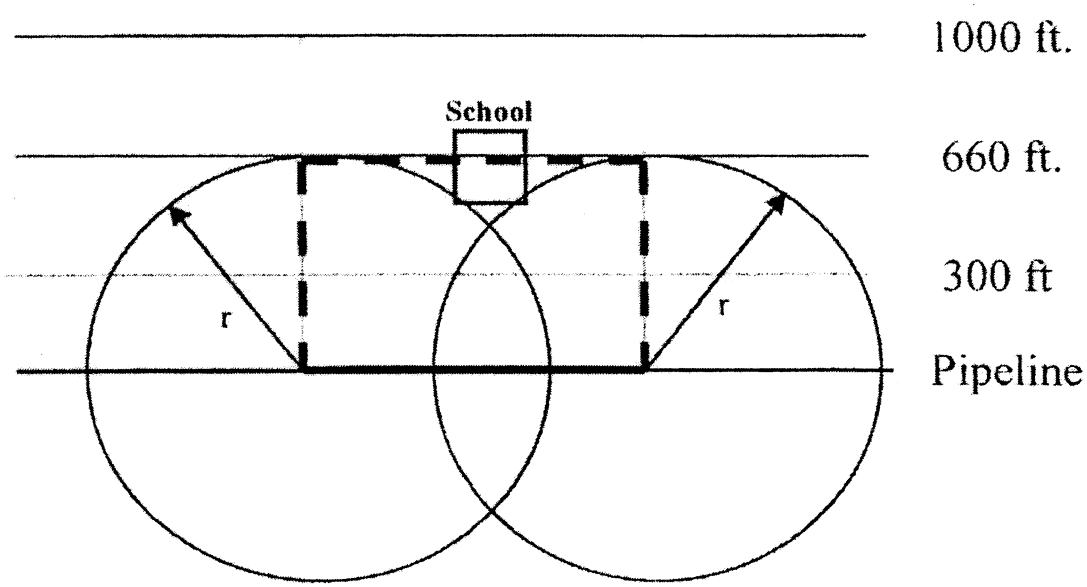
Potential Impact Zone
(Within dashed lines)



Note: This diagram represents the results for a 30" pipe with an MAOP of 1,000 psig.

Figure E.I.1 Potential Impact Zone (PIZ)

Figure E.II.1 Selection of Indirect Inspection Tools

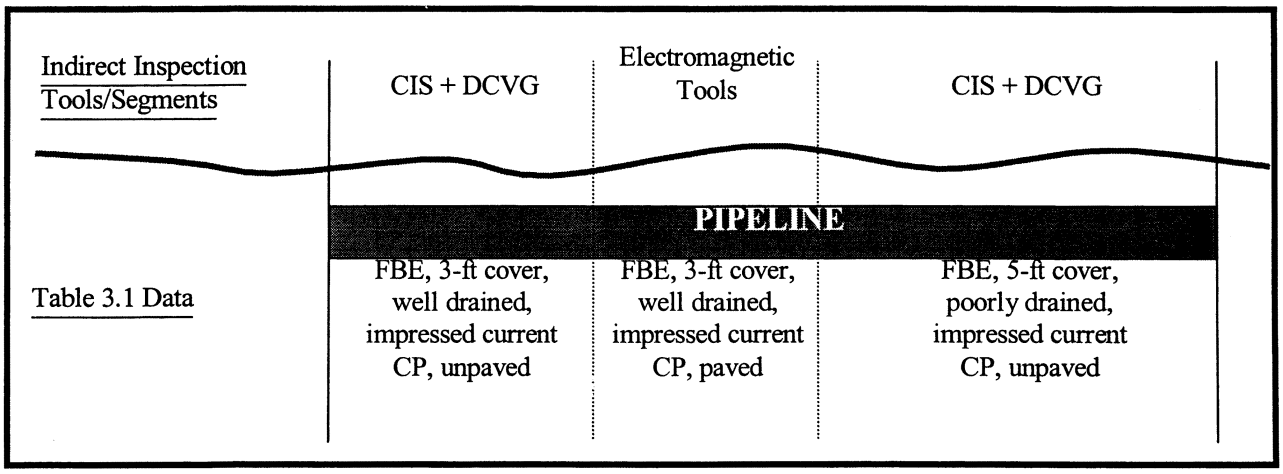


Figure E.II.2 Illustration of ECDA Region Definitions

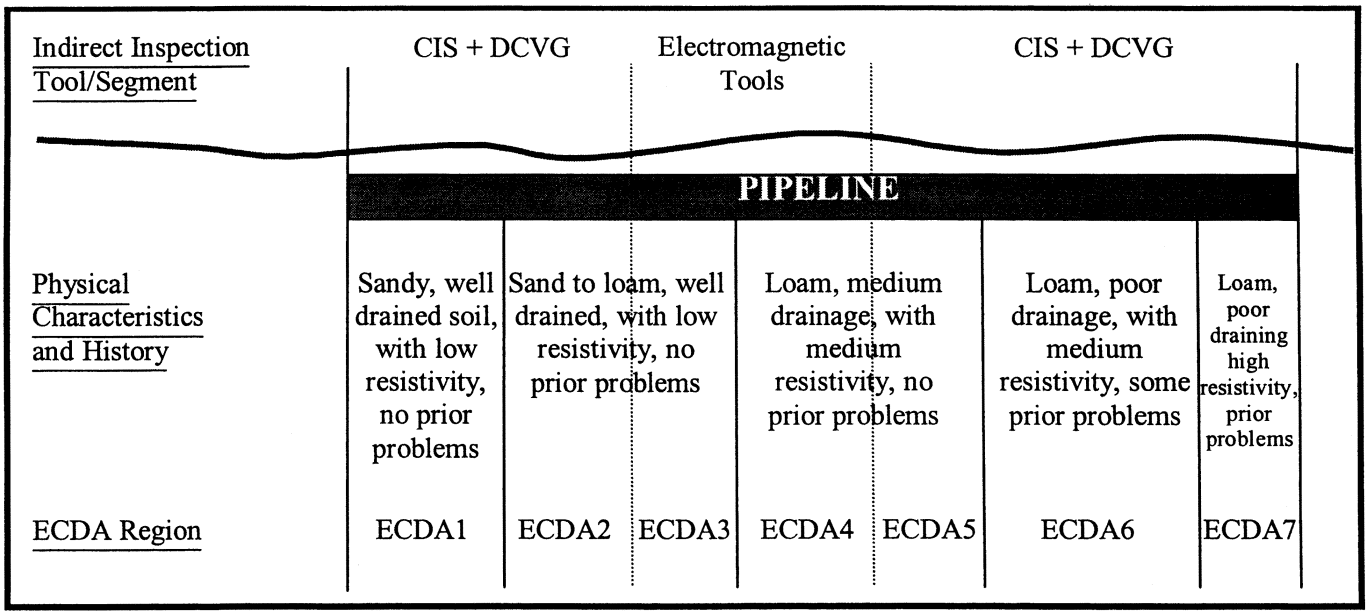


Table E.II.1: ECDA Data Elements

Data Elements	***Indirect Inspection Tool Selection***	***ECDA Region Definition***	***Use and Interpretation of Results***
PIPE RELATED			
Material (steel, cast iron etc) and grade	*ECDA not appropriate for nonferrous materials*	*Special considerations should be given to locations where dissimilar metals are joined*	*Can create local corrosion cells when exposed to the environment.*
Diameter	*May reduce detection capability of indirect inspection tools*		*Influences CP current flow and interpretation of results*
Wall thickness			*Impacts critical defect size and remaining life predictions*
Year Manufactured			*Older pipe materials typically have lower toughness levels, which reduces critical defect size and remaining life predictions.*
Seam Type		*Locations with pre-1970 low-frequency ERW pipe with increased selective seam corrosion susceptibility may require separate region*	*Older pipe typically has lower weld seam toughness that reduces critical defect size. Pre-1970 ERW pipe seams may be subject to higher corrosion rates than the base metal.*
Bare pipe	*Limits ECDA application. Less available tools*	Segments with bare pipe in coated pipelines should be in separate regions	Specific ECDA methods provided
CONSTRUCTION RELATED			
Year installed			Impacts time over which coating degradation may occur, defect population estimates, and corrosion rate estimates
Route changes/modifications		Changes may require separate regions. Year installed	

Route maps/aerial photos.		Provides general applicability info and region selection guidance.	Typically contain pipeline data that facilitate ECDA
Construction practices		Construction practice differences may require separate regions.	May indicate locations where construction problems may have occurred; e.g., backfill practices influence probability of coating damage during construction
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, insulating joints		Significant drains or changes in CP current should be considered separately; special considerations should be given to locations where dissimilar metals are connected	May impact local current flow and interpretation of results; dissimilar metals may create local corrosion cells at points of contact; coating degradation rates may be different from adjacent regions
Locations of and construction methods used at casings	May preclude use of some indirect inspection tools.	Requires separate ECDA regions	May require operator to extrapolate nearby results to inaccessible regions. Additional tools and other assessment activities may be required.
Locations of bends, including miter bends and wrinkle bends		Presence of miters and wrinkle bends may influence region selection.	Coating degradation rates may be different from adjacent regions; corrosion on miter and wrinkle bends can be localized, which affects local current flow and interpretation of results
Depth of cover	Restricts the use of some indirect inspection techniques	May require different ECDA regions for different ranges of depths of cover	May impact current flow and interpretation of results
Underwater sections; river crossings	Significantly restricts the use of many indirect inspection techniques	Requires separate ECDA regions	Changes current flow and interpretation of results
Locations of river weight and anchors		May require separate ECDA regions and reduces available indirect inspection tools	Influences current flow and interpretation of results; corrosion near weights and anchors can be localized, which affects local current flow and interpretation of results

Proximity to other pipelines, structures, HV electric transmission lines, and rail crossings	May preclude use of some indirect inspection methods	Regions where the CP currents are significantly affected by external sources should be treated as separate ECDA regions	Influences local current flow and interpretation of results

SOILS/ ENVIRONMENTAL

Soil characteristics/types Refer to Appendix B	Some soil characteristics reduce the accuracy of various indirect inspection techniques	Influences where corrosion is most likely; significant differences generally require separate ECDA regions	Can be useful in interpreting results. Influences corrosion rates and remaining life assessment.
Drainage		Influences where corrosion is most likely; significant differences may require separate ECDA regions	Can be useful in interpreting results. Influences corrosion rates and remaining life assessment.
Topography	Conditions such as rocky areas can make indirect inspections difficult or impossible		
Land Use (Current/past)	Paved roads etc will influence indirect inspection tool selection.	Can influence ECDA application and region selection	
Frozen ground	May impact applicability and effectiveness of some ECDA methods	Pipeline with some frozen areas should be considered in separate regions.	Influences current flow and interpretation of results

CORROSION CONTROL

CP system type (anodes , rectifiers and locations)	May affect ECDA tool selection		Localized use of sacrificial anodes within impressed current systems may influence indirect inspection. Influences current flow and interpretation of results
Stray current sources/locations			Influences current flow and interpretation of results
Test point locations (or pipe access points		May provide input when defining ECDA regions	
CP evaluation criteria			Used in Post–assessment analysis
CP maintenance history		Coating condition indicator	Can be useful in interpreting results

Years without CP applied		May make ECDA more difficult to apply	Negatively affects ability to estimate corrosion rates and make remaining life predictions
Coating Type - Pipe	ECDA may not be appropriate for coatings that cause shielding		Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.
Coating Type – Joints	ECDA not appropriate for coatings that cause shielding		Shielding due to certain joint coatings may lead to requirements for other assessment activities.
Coating condition	ECDA may be difficult to apply with severely degraded coatings		
Current Demand			Increasing current demand can indicate areas where coating degradation is leading to more exposed pipe surface area.
CP survey data/ history			Can be useful in interpreting results

OPERATIONAL DATA

Pipe operating temperature		Significant differences generally require separate ECDA regions	Can locally influence coating degradation rates.
Operating stress levels			Impacts critical flaw size and remaining life predictions
Monitoring programs- (Coupons, patrol, leak surveys etc.)		May provide input when defining ECDA regions	May impact repair, remediation, replacement schedules
Pipe inspection reports – excavation		May provide input when defining ECDA regions	
Repair history/ records – such as steel/composite repair sleeves, repair locations etc	May affect ECDA tool selection	Prior repair methods, such as anode additions) can create a local difference that may influence region selection	Provide useful data for post-assessment analyses such as interpreting data near repairs
Leak/rupture history(EC)		Can indicate condition of existing pipe	
Evidence of external MIC			MIC may accelerate external corrosion rates.

Type/ freq.– third party damage			High third party damage areas may have increased indirect inspection coating fault detects.
Data from previous over-the ground surveys			Essential for pre-assessment and region selection
Pressure test dates/pressures			Influences inspection intervals
Other prior integrity related activities –CIS, LI runs etc.	May impact ECDA tool selection – isolated vs. larger corroded areas		Useful post-assessment data

Table E.II.2: ECDA Tool Selection Matrix

CONDITIONS	CIS	DCVG	ACVG	Pearson	Electro-magnetic
Coating holidays	2	1,2	1,2	2	2
Third party damage	2	1,2	1,2	2	2
Anodic zones on bare pipe	2	NA	NA	NA	NA
Near river or water crossing	2	NA	NA	NA	2
Under frozen ground	NA	NA	NA	NA	2
Stray currents	2	1, 2	1, 2	2	2
Shielded corrosion activity (See Notes)	NA	NA	NA	NA	NA
Adjacent metallic structures	2	1, 2	1, 2	NA	2
Near parallel pipelines	2	1, 2	1, 2	NA	2
Under HVAC overhead elect transmission lines	2	1, 2	1, 2	2	NA
Shorted casing	2	1, 2	1, 2	2	2
Under paved roads	NA	NA	NA	NA	2
Uncased crossing	2	1, 2	1, 2	2	2
Cased crossing	NA	NA	NA	NA	2
At deep burial locations (See Notes)	2	1, 2	1, 2	2	2
Wetlands (Limited)	2	1, 2	1, 2	2	2
Rocky terrain/ rock ledges/rock backfill	NA	NA	NA	NA	2

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Notes

1 = Applicable: Small coating holidays (isolated & typically < 1sq. in.) and conditions that do not cause fluctuations in CP potentials under normal operating conditions.

2 = Applicable: Large coating holidays (isolated or continuous) or conditions that cause fluctuations in CP potentials under normal operating conditions.

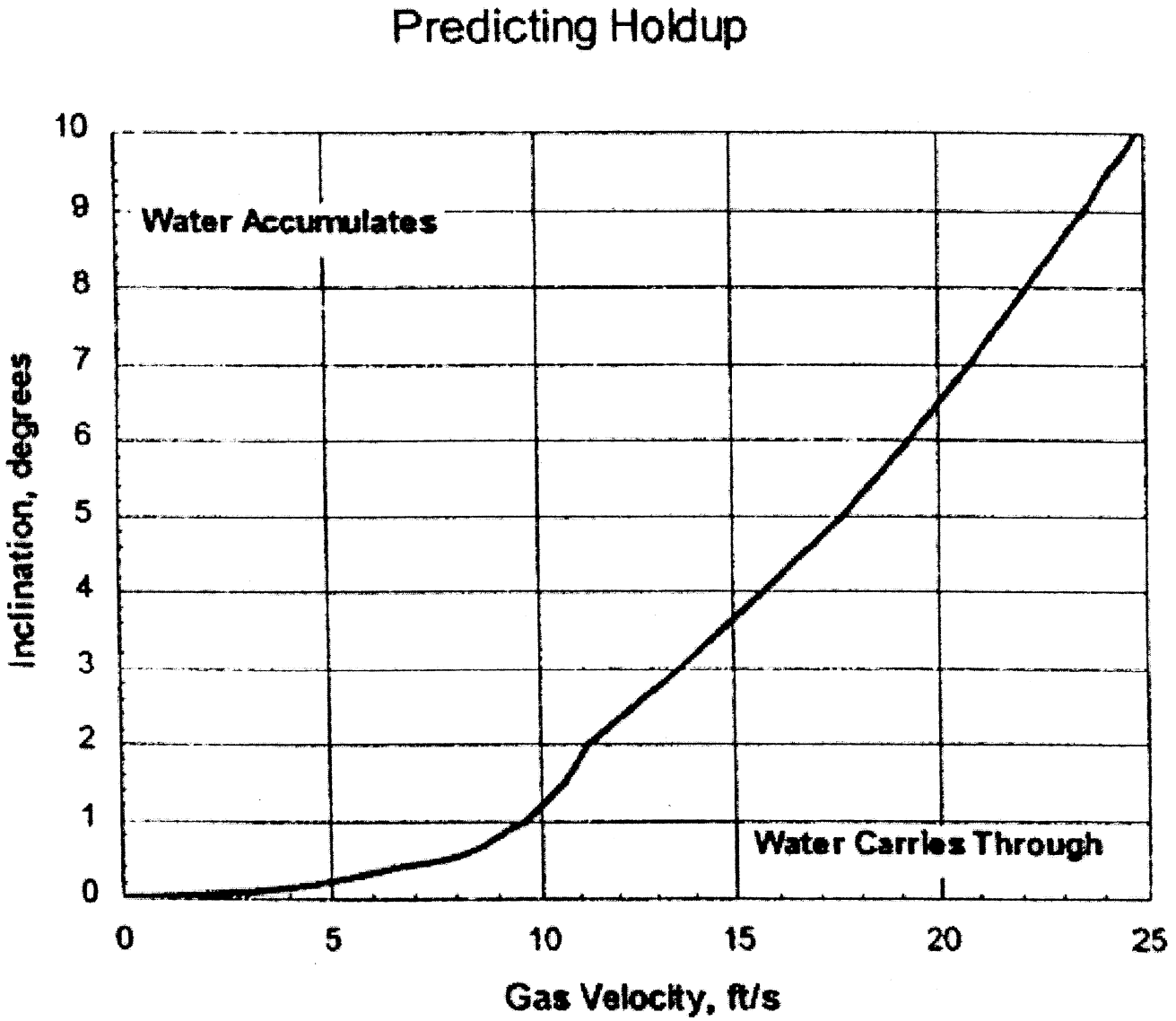
NA: Not Applicable to this tool without additional considerations.

Shielding by Disbonded Coating: None of these survey tools is capable in the detection of this type coating condition that exhibits no physical orifice to the soil. If there is a pathway to the soil through a small holiday or orifice, then tools such as DCVG or electromagnetic methods may detect these defect areas. This definition pertains to only one type of shielding from disbonded coatings. We also find current shielding from other metallic structures and from geological conditions.

Pipe Depths: All of the survey tools are sensitive in the detection of coating holidays where pipe burials exceed normal depths. Field conditions and terrain may affect depth ranges and detection sensitivity.

Limitations & Detection Capabilities: All survey methods are limited in sensitivity to the type and make up of the soil, presence of rock and rock ledges, type coating such as high dielectric tapes, construction practices, interference currents, other structures, etc. At least two or more survey methods may be required in order to get desired results and confidence levels required.

III. Internal Corrosion Direct Assessment of Gas Transmission Lines



Simple spreadsheet to calculate critical angle for liquid hold-up. Line diameter, pressure, and temperature are data inputs.

Graph E. III.1 Critical Angle for Liquid Hold-up

Issued in Washington, DC on January 22, 2003.

Stacey L. Gerard,

Associate Administrator for Pipeline Safety.

[FR Doc. 03–603 Filed 1–27–03; 8:45 am]

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Federal Register

Tuesday,
January 28, 2003

Part III

Securities and Exchange Commission

17 CFR Parts 240, 245, and 249
Insider Trades During Pension Fund Blackout Periods; Final Rule

SECURITIES AND EXCHANGE COMMISSION

17 CFR Parts 240, 245 and 249

[Release No. 34–47225; IC–25909; File No. S7–44–02]

RIN 3235–AI71

Insider Trades During Pension Fund Blackout Periods

AGENCY: Securities and Exchange Commission.

ACTION: Final rule.

SUMMARY: We are adopting rules that clarify the application and prevent evasion of Section 306(a) of the Sarbanes-Oxley Act of 2002. Section 306(a) prohibits any director or executive officer of an issuer of any equity security from, directly or indirectly, purchasing, selling or otherwise acquiring or transferring any equity security of the issuer during a pension plan blackout period that temporarily prevents plan participants or beneficiaries from engaging in equity securities transactions through their plan accounts, if the director or executive officer acquired the equity security in connection with his or her service or employment as a director or executive officer. In addition, the rules specify the content and timing of the notice that issuers must provide to their directors and executive officers and to the Commission about a blackout period. The rules are designed to facilitate compliance with the will of Congress as reflected in Section 306(a), and to eliminate the inequities that may result when pension plan participants and beneficiaries are temporarily prevented from engaging in equity securities transactions through their plan accounts.

DATES: *Effective Date:* January 26, 2003. *Compliance Date:* Issuers must comply with § 245.104(b)(3)(i) and (iii) of Regulation BTR beginning March 31, 2003.

FOR FURTHER INFORMATION CONTACT: Mark A. Borges, Special Counsel, Office of Rulemaking, at (202) 942–2910, or Anne Krauskopf, Special Counsel, Office of Chief Counsel, at (202) 942–2900, at the Division of Corporation Finance, United States Securities and Exchange Commission, 450 Fifth Street, NW, Washington, DC 20549–0312.

SUPPLEMENTARY INFORMATION: We are adopting new Regulation BTR [1] under the Securities Exchange Act of 1934 (the ''Exchange Act'')[2] and amendments to Exchange Act Rules 13a–11[3] and 15d–11[4] and to Forms 20–F,[5] 40–F [6] and 8–K [7] under the Exchange Act.

I. Introduction

On July 30, 2002, the Sarbanes-Oxley Act of 2002 (the ''Act'') was enacted.[8] Section 306(a) of the Act,[9] entitled ''Prohibition of Insider Trading During Pension Fund Blackout Periods,'' makes it unlawful for any director or executive officer of an issuer of any equity security, directly or indirectly, to purchase, sell or otherwise acquire or transfer any equity security of the issuer during any pension plan blackout period with respect to such equity security, if the director or executive officer acquired the equity security in connection with his or her service or employment as a director or executive officer.[10] Section 306(a) also requires an issuer to timely notify its directors and executive officers and the Commission of a blackout period that could affect them.[11] Section 306(a) takes effect January 26, 2003, 180 days after the date of enactment of the Act.[12]

Section 306(a) equalizes the treatment of corporate executives and rank-and-file employees with respect to their ability to engage in transactions involving issuer equity securities during a pension plan blackout period if the securities have been acquired in connection with their service to, or employment with, the issuer. When a director or executive officer engages in a transaction involving issuer equity securities at a time when participants or beneficiaries in the issuer's pension plans cannot engage in similar transactions through their plan accounts, the director or executive officer obtains an unfair advantage that the statute seeks to ameliorate. Section 306(a) restricts the ability of directors and executive officers to trade in such securities until a pension plan blackout period has ended and the ability to trade through the pension plan has been restored to plan participants and beneficiaries. This should align the interests of directors and executive officers more closely with those of the rank-and-file employees who engage in transactions involving issuer equity securities through an issuer's pension plans.

After consulting with the Secretary of Labor, we proposed new Regulation Blackout Trading Restriction (''BTR'') on November 6, 2002 to clarify the scope and operation of Section 306(a) and to prevent evasion of the statutory trading prohibition.[13] We received 18 letters commenting on the Proposing Release.[14] Many commenters suggested changes to the proposed rules to better achieve the purposes of section 306(a). Today, we are adopting Regulation BTR, which has been revised as discussed below, to incorporate a number of the changes recommended by commenters.

II. Regulation BTR

A. Statutory Trading Prohibition

As adopted, Regulation BTR addresses the operation of section 306(a) of the Act and its prohibition against trading in issuer equity securities by an issuer's directors and executive officers during a pension plan blackout period as follows:

- New Rule 100 [15] defines terms used in Section 306(a) and Regulation BTR.
- New Rule 101 [16] clarifies the operation of the Section 306(a) trading prohibition and establishes several exemptions from the prohibition.
- New Rule 102 [17] describes the exceptions to the definition of ''blackout period'' set forth in Section 306(a)(4)(A) of the Act.[18]
- New Rule 103 [19] clarifies the operation of the private remedy for a violation of the Section 306(a) trading prohibition, including a method for calculation of recoverable profits.
- New Rule 104 [20] sets forth the content and delivery requirements for the notice that an issuer must provide in connection with a blackout period.

As proposed and adopted, in order to give effect to section 306(a) in a manner consistent with Congressional intent, we are incorporating a number of concepts developed under Section 16 of the

[1] 17 CFR 245.100–104.

[2] 15 U.S.C. 78a *et seq.*

[3] 17 CFR 240.13a–11.

[4] 17 CFR 240.15d–11.

[5] 17 CFR 249.220f.

[6] 17 CFR 249.240f.

[7] 17 CFR 249.308.

[8] Pub. L. 107–204, 116 Stat. 745 (2002).

[9] 15 U.S.C. 7244(a).

[10] Section 306(a)(1) of the Act [15 U.S.C. 7244(a)(1)].

[11] Section 306(a)(6) of the Act [15 U.S.C. 7244(a)(6)].

[12] Section 306(c) of the Act [15 U.S.C. 7244(c)].

[13] Release No. 34–46778 (Nov. 2, 2002) [67 FR 69430] (the ''Proposing Release'').

[14] The commenters included six members of the legal and accounting communities, eight professional associations, three issuers and one individual investor. These comment letters and a summary of comments are available for public inspection and copying in our Public Reference Room, 450 Fifth Street, NW, Washington, DC 20549, in File No. S7–44–02. Public comments submitted electronically and the summary of comments is available on our Web site *http://www.sec.gov.*

[15] 17 CFR 245.100.

[16] 17 CFR 245.101.

[17] 17 CFR 245.102.

[18] 15 U.S.C. § 7244(a)(4)(A).

[19] 17 CFR 245.103.

[20] 17 CFR 245.104.

Exchange Act [21] into Regulation BTR. By doing so, we are able to take advantage of a well-established body of rules and interpretations concerning the trading activities of corporate insiders and, as to directors and executive officers of domestic issuers, facilitate enforcement of the Section 306(a) trading prohibition through monitoring of the reports publicly filed by directors and executive officers pursuant to Section 16(a) of the Exchange Act.[22]

B. Discussion

1. Issuers Subject to Trading Prohibition

Section 306(a) of the Act applies to directors and executive officers of issuers as defined in Section 2(a)(7) of the Act.[23] Consistent with this definition, new Rule 100(k) of Regulation BTR [24] provides that the term ''issuer'' means an issuer (as defined in Section 3(a)(8) of the Exchange Act [25]):

- The securities of which are registered under Section 12 of the Exchange Act; [26]
- That is required to file reports under Section 15(d) of the Exchange Act; [27] or
- That files, or has filed, a registration statement that has not yet become effective under the Securities Act of 1933 (the ''Securities Act'') [28] and that the issuer has not withdrawn.

Accordingly, Section 306(a) and Regulation BTR apply to the directors and executive officers of domestic issuers, foreign private issuers, small business issuers and, in rare instances, registered investment companies.[29]

While some commenters questioned the application of Section 306(a) to foreign private issuers,[30] the statute, by its terms, applies to these issuers.[31] However, Regulation BTR limits Section 306(a)'s application to the directors and executive officers of a foreign private issuer to situations where 50% or more of the participants or beneficiaries located in the United States in individual account plans maintained by the issuer are subject to a temporary trading suspension in issuer equity securities, and the affected participants and beneficiaries represent an appreciable portion of the issuer's worldwide employees.[32]

Similarly, Section 306(a) does not distinguish between large and small issuers. Accordingly, the statute applies to any entity that satisfies the definition of ''issuer'' under Section 2(a)(7) of the Act without regard to the entity's size, including a ''small business issuer.'' [33] One commenter indicated that the compliance burden for small business issuers would not be disproportionate to the benefits to be obtained from compliance with Section 306(a) since concerns related to trading by corporate insiders are not unique to large issuers.[34]

2. Persons Subject to Trading Prohibition

Section 306(a) of the Act applies to directors and executive officers of issuers subject to the Act. While one commenter expressly supported the proposed definitions for these terms,[35] some commenters suggested that we use the existing definition in Exchange Act Rule 3b–7 [36] to define the term ''executive officer.'' [37] We continue to believe that the broader definition in Exchange Act Rule 16a–1(f) [38] is more suitable for purposes of Section 306(a) and Regulation BTR because of its focus on the policy-making functions of the individual in question.[39] In addition, as some commenters noted, this definition will make it easier for domestic issuers to coordinate their trading policies for their corporate insiders who are subject to Section 16 of the Exchange Act and monitor compliance with both Section 16 and Section 306(a). Accordingly, new Rule 100(c)(1) of Regulation BTR [40] provides that, except in the case of a foreign private issuer, the term ''director'' has the meaning set forth in Section 3(a)(7) of the Exchange Act [41]

[21] 15 U.S.C. 78p. Because the purposes of Section 306(a) of the Act and Section 16 of the Exchange Act are not identical, however, we note that Section 306(a) and Regulation BTR will not always be interpreted the same as Section 16 if these purposes diverge or the interests of investors require a different interpretation.

[22] 15 U.S.C. 78p(a).

[23] 15 U.S.C. 7201(7).

[24] 17 CFR 245.100(k).

[25] 15 U.S.C. 78c(a)(8). Section 3(a)(8) of the Exchange Act defines the term ''issuer'' to mean ''any person who issues or proposes to issue any security; except that with respect to certificates of deposit for securities, voting-trust certificates, or collateral-trust certificates, or with respect to certificates of interest or shares in an unincorporated investment trust not having a board of directors or of the fixed, restricted management, or unit type, the term ''issuer'' means the person or persons performing the acts and assuming the duties of depositor or manager pursuant to the provisions of the trust or other agreement or instrument under which such securities are issued; and except that with respect to equipment-trust certificates or like securities, the term ''issuer'' means the person by whom the equipment or property is, or is to be, used.''

[26] 15 U.S.C. 78*l*.

[27] 15 U.S.C. 78o(d).

[28] 15 U.S.C. 77a *et seq.*

[29] For a discussion of the application of Regulation BTR to registered investment companies, see the Proposing Release at Section II.B.1.d.

[30] *See* the Letter dated December 24, 2002 of the American Bar Association (the ''ABA Letter'') and the Letter dated November 27, 2002 of the Organization for International Investment.

[31] Exchange Act Rule 3b–4(c) [17 CFR 240.3b–4(c)] defines the term ''foreign private issuer'' to mean ''any foreign issuer other than a foreign government except an issuer meeting the following conditions: (1) more than 50% of the issuer's outstanding voting securities are directly or indirectly held of record by residents of the United States; and (2) any of the following: (i) The majority of the executive officers or directors are United States citizens or residents; (ii) more than 50% of the assets of the issuer are located in the United States; or (iii) the business of the issuer is administered principally in the United States.''

[32] *See* Section II.B.5.d below.

[33] Item 10(a)(1) of Regulation S–B [17 CFR 228.10(a)(1)] defines the term ''small business issuer'' to mean ''a company that meets all of the following criteria: (i) Has revenues of less than $25,000,000; (ii) is a U.S. or Canadian issuer; (iii) is not an investment company; and (iv) if a majority-owned subsidiary, the parent corporation is also a small business issuer. *Provided however*, that an entity is not a small business issuer if it has a public float (the aggregate market value of the issuer's outstanding securities held by non-affiliates) of $25,000,000 or more.''

[34] *See* the Letter dated December 16, 2002 of PricewaterhouseCoopers LLP (the ''PWC Letter'').

[35] *See* the PWC Letter.

[36] 17 CFR 240.3b–7. This definition differs from the definition in Exchange Act Rule 16a–1(f) [17 CFR 240.16a–1(f)] in that it does not expressly include an issuer's principal financial officer or principal accounting officer (or controller). It also does not expressly cover officers of a parent corporation or explain how to identify an issuer's executive officers when the issuer is a limited partnership or trust.

[37] *See* the Letter dated December 16, 2002 of America's Community Bankers (the ''ACB Letter'') and the Letter dated December 16, 2002 of the Profit Sharing/401k Council of America (the ''PSCA Letter'').

[38] Exchange Act Rule 16a–1(f) defines the term ''officer'' to mean ''an issuer's president, principal financial officer, principal accounting officer (or, if there is no such accounting officer, the controller), any vice-president of the issuer in charge of a principal business unit, division or function (such as sales, administration or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the issuer. Officers of the issuer's parent(s) or subsidiaries shall be deemed officers of the issuer if they perform such policy-making functions for the issuer. In addition, when the issuer is a limited partnership, officers or employees of the general partner(s) who perform policy-making functions for the limited partnership are deemed officers of the limited partnership. When the issuer is a trust, officers or employees of the trustee(s) who perform policy-making functions for the trust are deemed officers of the trust.''

[39] Thus, the standard for determining whether an individual is an ''executive officer'' for purposes of Section 306(a) of the Act and Regulation BTR is the same as the standard applicable under Exchange Act Rule 16a–1(f). For example, the term ''policy-making functions'' does not include policy-making functions that are not significant. Similarly, if pursuant to Item 401(b) of Regulation S–K [17 CFR 229.401(b)], an issuer identifies an individual as an ''executive officer,'' it will be presumed that the board of directors of the issuer made that judgment and that the individuals so identified are executive officers of the issuer for purposes of Section 306(a) and Regulation BTR, as are such other persons enumerated in Exchange Act Rule 16a–1(f) but not in Item 401(b). See the note to Exchange Act Rule 16a–1(f).

[40] 17 CFR 245.100(c)(1).

[41] 15 U.S.C. 78c(a)(7). As we have previously noted, this definition reflects a functional and

Continued

and new Rule 100(h)(1)[42] provides that, except in the case of a foreign private issuer, the term ''executive officer'' has the same meaning as the term ''officer'' in Exchange Act Rule 16a–1(f).

In the case of a foreign private issuer, the commenters supported our proposal to specifically identify the directors and executive officers that are subject to the Section 306(a) trading prohibition.[43] Thus, new Rule 100(c)(2) of Regulation BTR[44] provides that the term ''director'' means a director who is a management employee of the issuer and new Rule 100(h)(2)[45] provides that the term ''executive officer'' means the principal executive officer or officers, the principal financial officer or officers and the principal accounting officer or officers of the issuer.

3. Securities Subject to Trading Prohibition

Section 306(a) of the Act applies to any equity security of an issuer other than an exempt security.[46] We did not receive any comments regarding the proposed definitions for the terms ''equity security,'' ''equity security of the issuer'' and ''derivative security.'' Accordingly, new Rule 100(e) of Regulation BTR[47] provides that the term ''equity security'' has the meaning set forth in Section 3(a)(11) of the Exchange Act[48] and Exchange Act Rule 3a11–1,[49] new Rule 100(f)[50] provides that the term ''equity security of the issuer'' includes any equity security or derivative security relating to an issuer, whether or not issued by that issuer, and new Rule 100(d)[51] provides that the term ''derivative security'' has the same meaning as in Exchange Act Rule 16a–1(c).[52]

In the case of a derivative security, the definition in new Rule 100(d) is to be interpreted in a manner consistent with the rules and interpretations under Section 16 of the Exchange Act. For example, an interest that may be settled only in cash, but the value of which is denominated or based on an equity security, such as phantom stock, will be considered a derivative security for purposes of Section 306(a) and Regulation BTR. Consequently, an acquisition of a ''cash-only'' derivative security or the exercise, sale or other transfer of the security during a blackout period will be subject to the Section 306(a) trading prohibition unless the transaction qualifies as an exempt transaction under Regulation BTR.

4. Transactions Subject to Trading Prohibition

Section 306(a) of the Act makes it unlawful for a director or executive officer of an issuer of any equity security, directly or indirectly,[53] to purchase, sell or otherwise acquire or transfer any equity security of the issuer during a pension plan blackout period with respect to the equity security, if the director or executive officer ''acquires such equity security in connection with his or her service or employment as a director or executive officer.'' While Section 306(a) uses the word ''acquires'' to describe the equity securities that are subject to the statutory trading prohibition, we believe that Congress intended to cover both equity securities that a director or executive officer ''acquired'' before, or ''acquires'' during, a pension plan blackout period.[54] Thus, we read the Section 306(a) trading prohibition to cover:

- An acquisition of issuer equity securities by a director or executive officer during a blackout period if the acquisition is in connection with his or her service or employment as a director or executive officer; and
- A disposition of issuer equity securities by a director or executive officer during a blackout period if the disposition involves issuer equity securities acquired in connection with his or her service or employment as a director or executive officer.[55]

flexible approach to determining whether a person is a director of an entity. *See* Release No. 34–46685 (Oct. 18, 2002) [67 FR 65325] at n. 7. Thus, for purposes of Section 306(a) of the Act and Regulation BTR, an individual's title is not dispositive as to whether he or she is a director. As under Section 16 of the Exchange Act, attention must be given to the individual's underlying responsibilities or privileges with respect to the issuer and whether he or she has a significant policy-making role with the issuer. *See* Release No. 34–28869 (Feb. 21, 1991) [56 FR 7242], at Section II.A.1. An individual may hold the title ''director'' and yet, because he or she is not acting as such, not be deemed a director. Release No. 34–26333 (Dec. 2, 1988) [53 FR 49997], at Section III.A.2.

[42] 17 CFR 245.100(h)(1).

[43] *See* the ABA Letter and the Letter dated December 16, 2002 of Cleary, Gottlieb, Steen & Hamilton (the ''Cleary Letter'').

[44] 17 CFR 245.100(c)(2).

[45] 17 CFR 245.100(h)(2).

[46] New Rule 100(i) of Regulation BTR [17 CFR 245.100(i)] defines the term ''exempt security'' by reference to the definition in Section 3(a)(12) of the Exchange Act [15 U.S.C. 78c(a)(12)].

[47] 17 CFR 245.100(e).

[48] 15 U.S.C. 78c(a)(11). Section 3(a)(11) of the Exchange Act defines the term ''equity security'' to mean ''any stock or similar security; or any security future on any such security; or any security convertible, with or without consideration, into such a security, or carrying any warrant or right to subscribe to or purchase such a security; or any such warrant or right; or any other security which the Commission shall deem to be of similar nature and consider necessary or appropriate, by such rules and regulations as it may prescribe in the public interest or for the protection of investors, to treat as an equity security.''

[49] 17 CFR 240.3a11–1. Exchange Act Rule 3a11–1 defines the term ''equity security'' to mean ''any stock or similar security, certificate of interest or participation in any profit sharing agreement, preorganization certificate or subscription, transferable share, voting trust certificate or certificate of deposit for an equity security, limited partnership interest, interest in a joint venture, or certificate of interest in a business trust; any security future on any such security; or any security convertible, with or without consideration into such a security, or carrying any warrant or right to subscribe to or purchase such a security; or any such warrant or right; or any put, call, straddle, or other option or privilege of buying such a security from or selling such a security to another without being bound to do so.''

[50] 17 CFR 245.100(f).

[51] 17 CFR 245.100(d).

[52] 17 CFR 240.16a–1(c). Exchange Act Rule 16a–1(c) defines the term ''derivative securities'' to mean ''any option, warrant, convertible security, stock appreciation right, or similar right with an exercise or conversion privilege at a price related to an equity security, or similar securities with a value derived from the value of an equity security, but shall not include: (1) Rights of a pledgee of securities to sell the pledged securities; (2) rights of all holders of a class of securities of an issuer to receive securities pro rata, or obligations to dispose of securities, as a result of a merger, exchange offer, or consolidation involving the issuer of the securities; (3) rights or obligations to surrender a security, or have a security withheld, upon the receipt or exercise of a derivative security or the receipt or vesting of equity securities, in order to satisfy the exercise price or the tax withholding consequences of receipt, exercise or vesting; (4) interests in broad-based index options, broad-based index futures, and broad-based publicly traded market baskets of stocks approved for trading by the appropriate federal governmental authority; (5) interests or rights to participate in employee benefit plans of the issuer; or (6) rights with an exercise or conversion privilege at a price that is not fixed; or (7) options granted to an underwriter in a registered public offering for the purpose of satisfying over-allotments in such offering.''

[53] Under Regulation BTR, a purchase, sale or other acquisition or transfer of an equity security will be attributed to a director or executive officer if he or she has a pecuniary interest in the transaction. To promote consistency and to simplify compliance, new Rule 100(*l*) of Regulation BTR [17 CFR 100(*l*)] defines the terms ''pecuniary interest'' and ''indirect pecuniary interest'' by reference to the definitions in Exchange Act Rule 16a–1(a)(2) [17 CFR 240.16a–1(a)(2)]. The definition in new Rule 100(*l*) also encompasses the portfolio exclusion of Exchange Act Rule 16a–1(a)(2)(iii) [17 CFR 240.16a–1(a)(2)(iii)].

[54] This interpretation of the statute is reflected in new Rule 101(a) of Regulation BTR [17 CFR 245.101(a)].

[55] Accordingly, a transaction involving equity securities that are not acquired in connection with service or employment as a director or executive officer is not subject to the Section 306(a) trading prohibition.

(a) ''*Acquired in Connection with Service or Employment as a Director or Executive Officer*''.

As adopted, new Rule 100(a) of Regulation BTR [56] defines the term ''acquired such equity security in connection with service or employment as a director or executive officer'' to include equity securities acquired by a director or executive officer:

- At a time when he or she was a director or executive officer under a compensatory plan, contract, authorization or arrangement,[57] including, but not limited to, plans relating to options, warrants or rights, pension, retirement or deferred compensation or bonus, incentive or profit-sharing (whether or not set forth in any formal plan document), including a compensatory plan, contract, authorization or arrangement with a parent, subsidiary or affiliate;
- At a time when he or she was a director or executive officer as a result of any transaction or business relationship described in paragraph (a) or (b) of Item 404 of Regulation S–K [58] or, in the case of a foreign private issuer, Item 7.B of Form 20–F (but without application of the disclosure thresholds of such provisions), to the extent that he or she has a pecuniary interest [59] in the equity securities;
- At a time when he or she was a director or executive officer, as ''director's qualifying shares'' or other securities that he or she must hold to satisfy minimum ownership requirements or guidelines for directors or executive officers;
- Prior to becoming, or while, a director or executive officer where the equity security was acquired as a direct or indirect inducement to service or employment as a director or executive officer; or
- Prior to becoming, or while, a director or executive officer where the equity security was received as a result of a business combination in respect of an equity security of an entity involved in the business combination that he or she had acquired in connection with service or employment as a director or executive officer of that entity.

Several commenters expressed concern that, as proposed, the definition was overly broad.[60] One commenter objected to treating equity securities acquired in an arms-length, commercial transaction that is subject to disclosure under Item 404(a) or (b) of Regulation S–K as ''acquired in connection with service or employment as a director or executive officer.''[61] While this aspect of the definition may reach equity securities that were, in fact, acquired in arms-length, commercial transactions, we believe that it is necessary to prevent evasion of the trading prohibition of Section 306(a) of the Act.

Some commenters opposed treating equity securities acquired to satisfy minimum ownership requirements or guidelines as subject to the Section 306(a) trading prohibition, arguing that securities purchased in the open market are not ''acquired in connection with service or employment as a director or executive officer,'' regardless of the extrinsic motivation, and that the proposed definition was contrary to the statutory language and the intent of Section 306(a).[62] They also asserted that requiring a director or executive officer subject to minimum ownership requirements or guidelines to identify and track equity securities purchased in the open market to satisfy such requirements or guidelines would impose an unjustified administrative burden.

We agree that equity securities purchased in the open market before an individual becomes a director or executive officer (and, thus, before the minimum ownership requirements or guidelines apply) should not be subject to the Section 306(a) trading prohibition even if they are used to satisfy the ownership requirements or guidelines after the individual becomes a director or executive officer. We, therefore, revised this aspect of the definition to indicate that equity securities used as directors' qualifying shares or to satisfy an issuer's minimum security ownership requirements or guidelines will be considered ''acquired in connection with service or employment as a director or executive officer'' only where an individual acquires the equity securities at a time when he or she is a director or executive officer of the issuer. Since these equity securities are clearly ''acquired in connection with service or employment as a director or executive officer,'' we do not believe that it is overly burdensome to require directors and executive officers to identify and track these securities for purposes of Section 306(a).

Some commenters objected to treating equity securities acquired by an individual before becoming a director or executive officer as ''acquired in connection with service or employment as a director or executive officer'' if the equity securities were awarded to induce the individual to become an employee or non-executive officer of the issuer.[63] These commenters argued that subjecting these equity securities to the statutory trading prohibition at the time an employee or non-executive officer is promoted to director or executive officer status was contrary to the statutory language and did not serve the goals of Section 306(a). They suggested that inducement awards be treated as ''acquired in connection with service or employment as a director or executive officer'' only if they are directly related to an individual becoming a director or executive officer. Because, in some situations, an equity securities award to an individual joining an issuer as an employee or non-executive officer may be an inducement related to subsequent service or employment as a director or executive officer, we chose not to exclude inducement awards related to becoming an employee or non-executive officer from the definition. Instead, to ensure that this type of inducement award is not used to evade the statutory trading prohibition, we revised the definition to make it clear that an award acquired as a direct or indirect inducement to service or employment as a director or executive officer will be considered ''acquired in connection with service or employment as a director or executive officer.'' Awards that are an inducement to becoming an employee or non-executive officer, but are not a direct or indirect inducement to service or employment as a director or executive officer, will not be considered ''acquired in connection with service or employment as a director or executive officer.''

Finally, commenters requested clarification on one other aspect of the definition. New Rule 100(a)(5) of Regulation BTR [64] makes clear that, in the case of equity securities acquired in connection with a merger, consolidation or other business combination by an individual who was a director or executive officer of the target entity and is to become a director or executive officer of the acquiring entity at the time

[56] 17 CFR 245.100(a).

[57] The scope of the phrase ''compensatory plan, contract, authorization or arrangement'' includes a ''plan'' as defined in Item 402(a)(7)(ii) of Regulation S–K [17 CFR 229.402(a)(7)(ii)], as well as an ''employee benefit plan'' as defined in Securities Act Rule 405 [17 CFR 230.405].

[58] 17 CFR 229.404(a) or (b). The descriptions in Item 404(a) and (b) of Regulation S–K are to be used without regard to whether the issuer is a ''small business issuer'' subject to the disclosure requirements of Regulation S–B [17 CFR 228.10 *et seq.*].

[59] *See* n. 53 above.

[60] *See* the ABA Letter, the ACB Letter, the PSCA Letter, the PWC Letter and the Letter dated December 16, 2002 of Sullivan & Cromwell (the ''S&C Letter'').

[61] *See* the ACB Letter.

[62] *See* the ABA Letter, the PSCA Letter and the S&C Letter.

[63] *See* the ACB Letter and the S&C Letter.

[64] 17 CFR 245.100(a)(5).

of, or following the completion of, the transaction, the securities will be considered ''acquired in connection with service or employment as a director or executive officer'' to the extent that they are received in respect of equity securities of the target entity that were ''acquired in connection with service or employment as a director or executive officer'' of the target entity.[65] For example, where an executive officer of a target entity becomes an executive officer of the acquiring entity in connection with a business combination and, in the transaction, receives equity securities of the acquiring entity in respect of equity securities of the target entity that he or she owned, the equity securities received will be considered ''acquired in connection with service or employment as a director or executive officer'' only to the extent that they are received in respect of securities that were previously ''acquired in connection with service or employment as a director or executive officer'' of the target entity.

(b) *Service or Employment Presumption.*

To simplify identification of equity securities involved in a disposition subject to the trading prohibition of Section 306(a)(1) of the Act and to prevent evasion of the trading prohibition, we proposed an irrebuttable presumption that any equity securities sold or otherwise transferred during a blackout period were ''acquired in connection with service or employment as a director or executive officer'' to the extent that a director or executive officer owned such securities at the time of the transaction, without regard to the actual source of the securities. One commenter supported the proposed presumption, citing the difficulty in tracing the actual source of the securities disposed.[66] However, most commenters opposed the presumption, asserting that because it would treat all equity securities held as fungible, it would act as an absolute bar on sales or other dispositions during a blackout period, regardless of how the securities actually were acquired. [67] Some commenters indicated that, because a violation of Section 306(a)(1) is not limited to a private action for profit recovery, an irrebuttable presumption would potentially expose directors and executive officers to civil and criminal penalties.[68] They argued that the proposed presumption would effectively erase the ''acquired in connection with service or employment as a director or executive officer'' requirement from Section 306(a) of the Act.

These commenters encouraged us to permit directors and executive officers to specifically identify, or ''trace,'' the source of equity securities sold or otherwise transferred during a blackout period to establish that the transaction did not involve securities ''acquired in connection with service or employment as a director or executive officer.'' They pointed out that because ''tracing'' is permitted under both the Internal Revenue Code [69] and some federal securities laws,[70] it would not impose an undue burden on directors and executive officers.

We are persuaded by these comments that an irrebuttable presumption is unnecessary. Accordingly, new Rule 101(b) of Regulation BTR [71] provides that any equity securities sold or otherwise transferred during a blackout period by a director or executive officer of an issuer will be considered to have been ''acquired in connection with service or employment as a director or executive officer'' to the extent that the director or executive officer owned such securities at the time of the transaction, unless he or she establishes that the equity securities were not ''acquired in connection with service or employment as a director or executive officer.'' To establish this defense, a director or executive officer must specifically identify the origin of the equity securities in question (which must not be ''acquired in connection with service or employment as a director or executive officer'' as defined in new Rule 100(a)), and demonstrate that this identification of the equity securities is consistent for all purposes related to the transaction (such as tax reporting and any applicable disclosure and reporting requirements).[72]

For example, if an executive officer owned 1,000 shares of an issuer's common stock, 250 shares of which were acquired as the result of the exercise of an employee stock option, a sale of 250 shares of common stock during a blackout period will be treated as a sale of the option shares and, therefore, subject to the Section 306(a) trading prohibition, unless the executive officer establishes a different source of the shares sold and this identification is consistent for all purposes related to the transaction (such as tax reporting and any applicable disclosure and reporting requirements).

(c) *Transitional Situations.*

Except as provided in new Rule 100(a), equity securities acquired by an individual before he or she becomes a director or executive officer are not ''acquired in connection with service or employment as a director or executive officer'' for purposes of Section 306(a) of the Act. Thus, equity securities acquired under a compensatory plan, contract, authorization or arrangement while an individual is an employee, but not a director or executive officer, will not be subject to the Section 306(a) trading prohibition. However, equity securities acquired by an employee before becoming a director or executive officer will be considered ''acquired in connection with service or employment as a director or executive officer'' if the equity securities are part of an inducement award.[73]

In contrast, equity securities acquired by an individual in connection with service or employment as a director or executive officer before an entity becomes an ''issuer'' (as defined in Section 2(a)(7) of the Act and new Rule 100(k)) are considered ''acquired in connection with service or employment as a director or executive officer'' for purposes of Section 306(a) and Regulation BTR and are subject to the statutory trading prohibition. Similarly, equity securities acquired by a director or executive officer in connection with his or her service or employment as a director or executive officer of an ''issuer'' (as defined in Section 2(a)(7) of the Act and new Rule 100(k)) before the effective date of Section 306(a) are subject to that section and Regulation BTR.

(d) *Exempt Transactions.*

Because some transactions by a director or executive officer involving issuer equity securities do not present the concerns that Section 306(a) of the Act is intended to remedy, we are adopting new Rule 101(c) of Regulation BTR,[74] which exempts from the statutory trading prohibition:

[65] In addition, equity securities acquired in connection with a merger, consolidation or other business combination by an individual (whether or not a director or executive officer of the target entity) as an inducement to becoming a director or executive officer of the acquiring entity will be considered ''acquired in connection with service or employment as a director or executive officer.'' See new Rule 100(a)(4) of Regulation BTR [17 CFR 245.100(a)(4)].

[66] *See* the PWC Letter.

[67] *See*, for example, the ABA Letter, the Letter dated December 16, 2002 of Intel Corporation (the ''Intel Letter'') and the PSCA Letter.

[68] *See* the ABA Letter and the S&C Letter.

[69] *See* Treas. Reg. 1.1012–1(c).

[70] *See*, for example, Securities Act Rule 144(d) [17 CFR 230.144(d)].

[71] 17 CFR 245.101(b).

[72] While not required, a director or executive officer may want to add a note describing the date and nature of the transaction in which the securities were acquired in the ''Explanation of Responses'' section of the Form 4 [17 CFR 249.104] reporting the transaction.

[73] *See* the discussion in Section II.B.4.a above.

[74] 17 CFR 245.101(c).

• Acquisitions of equity securities under dividend or interest reinvestment plans;

• Purchases or sales of equity securities pursuant to a trading arrangement that satisfies the affirmative defense conditions of Exchange Act Rule 10b5–1(c);[75]

• Purchases or sales of equity securities, other than discretionary transactions,[76] pursuant to certain ''tax-conditioned'' plans;[77] and

• Increases or decreases in the number of equity securities held as a result of a stock split or stock dividend applying equally to all equity securities of that class.

While commenters generally supported the proposed exemptions, some requested clarification as to the intent of the statement in the Proposing Release that ''[a]wareness of an impending blackout period would be considered awareness of material, non-public information that could render the [proposed exemption for a trading arrangement that satisfies the affirmative defense conditions of Exchange Act Rule 10b5–1(c)] unavailable.'' In particular, commenters expressed concern that the statement could have implications beyond Section 306(a). One commenter noted that a broad reading of this statement could preclude a director or executive officer from establishing an Exchange Act Rule 10b5–1(c) trading arrangement indefinitely if he or she was aware that a pension plan blackout period was planned, even if the dates of the blackout period had not been established.[78] The same commenter asserted that the statement would not permit a director or executive officer to evaluate the materiality of his or her knowledge about an impending blackout period on the basis of applicable facts and circumstances. Another commenter noted that the statement created uncertainty as to whether ''awareness'' of an impending blackout period was material non-public information that would preclude trading in an issuer's securities by any person with such awareness until the blackout period was publicly disclosed.[79] A third commenter suggested that we clarify the statement to provide that ''awareness'' of an impending blackout period would require awareness of the actual or approximate beginning and ending dates of a specific blackout period (whether or not notice of the blackout period as required by Section 306(a)(6) of the Act had been received).[80]

We did not intend for this statement to be read so broadly. The statement simply was intended to clarify that a director or executive officer who is aware of a scheduled blackout period could not subsequently enter into or modify an Exchange Act Rule 10b5–1(c) trading arrangement to circumvent the Section 306(a) trading prohibition. The ''awareness'' of an impending blackout period described in the statement would require awareness of the actual or approximate beginning or ending dates of a specific blackout period (whether or not notice of the blackout period as required by Section 306(a)(6) had been received), and not merely awareness of the potential for a blackout period. Accordingly, we have modified new Rule 101(c)(2) of Regulation BTR[81] to provide that transactions pursuant to a trading arrangement that satisfies the affirmative defense conditions of Exchange Act Rule 10b5–1(c) will be exempt from the Section 306(a) trading prohibition, as long as the arrangement is not entered into or modified during the blackout period in question or at a time when the director or executive officer is aware of the actual or approximate beginning or ending dates of the blackout period, whether or not the director or executive officer has received notice of the blackout period as required by Section 306(a)(6). This information may or may not be material non-public information for other purposes, depending on the applicable facts, including whether the information has not been disclosed or otherwise made public and whether the information is material under customary legal analysis.[82] We do not intend that our treatment of this information under Regulation BTR affect that customary legal analysis of materiality.

The exemption for purchases or sales of equity securities pursuant to certain ''tax-conditioned'' plans in new Rule 101(c)(3) of Regulation BTR[83] has been expanded to include purchases or sales pursuant to an employee benefit plan of a foreign private issuer that either has been approved by the taxing authority of a foreign jurisdiction, or is eligible for preferential treatment under the tax laws of a foreign jurisdiction because the plan provides for broad-based employee participation. This change is intended to equalize the treatment of directors and executive officers of domestic and foreign private issuers where a foreign issuer has an employee benefit plan maintained outside the United States that is substantially similar to a ''tax-conditioned'' employee benefit plan.[84]

As adopted, the exemption in new Rule 101(c)(3) does not extend to ''discretionary transactions,'' such as an intra-plan transfer involving an issuer equity securities fund or a cash distribution funded by a volitional disposition of an issuer equity security, that occur during a blackout period. However, it would cover acquisitions or dispositions of equity securities made in connection with death, disability, retirement or termination of employment or transactions involving a diversification or distribution required by the Internal Revenue Code to be made available to plan participants because these transactions are not ''discretionary transactions.''[85]

We have expanded new Rule 101(c) to include the following additional exemptions from the statutory trading prohibition that were suggested by commenters:

• Compensatory grants and awards of equity securities (including options and stock appreciation rights) pursuant to a plan that, by its terms, permits directors or executive officers to receive grants or awards, provides for grants or awards to occur automatically and specifies the terms and conditions of the grants or awards;

• Exercises, conversions or terminations of derivative securities that were not written or acquired by a director or executive officer during the blackout period in question or while aware of the actual or approximate beginning or ending dates of the blackout period, and where (i) the derivative security, by its terms, may be exercised, converted or terminated only on a fixed date, with no discretionary provision for earlier exercise, conversion or termination,[86] or (ii) the derivative security is exercised, converted or terminated by a counterparty and the director or

[75] 17 CFR 240.10b5–1(c).

[76] As defined in Exchange Act Rule 16b–3(b)(1) [17 CFR 240.16b–3(b)(1)].

[77] These plans include Qualified Plans (as defined in Exchange Act Rule 16b–3(b)(4) [17 CFR 240.16b–3(b)(4)]), Excess Benefit Plans (as defined in Exchange Act Rule 16b–3(b)(2) [17 CFR 240.16b–3(b)(2)]) and Stock Purchase Plans (as defined in Exchange Act Rule 16b–3(b)(5) [17 CFR 240.16b–3(b)(5)]) and, with respect to foreign private issuers, specified similar plans. See n. 83 below and the accompanying text. Some commenters requested exemptions for specific transactions under these ''tax-conditioned'' plans. As discussed in this section, we do not believe that these exemptions are necessary. *See* n. 85 below and the accompanying text.

[78] *See* the PSCA Letter.

[79] *See* the Intel Letter.

[80] *See* the ABA Letter.

[81] 17 CFR 245.101(c)(2).

[82] *See TSC Industries, Inc.* v. *Northway, Inc.,* 426 U.S. 438 (1976); *Basic, Inc.* v. *Levinson,* 485 U.S. 224 (1988).

[83] 17 CFR 245.101(c)(3).

[84] *See* n. 77 above.

[85] *See* n. 76 above.

[86] For example, European-style options.

executive officer does not exercise any influence on the counterparty with respect to whether or when to exercise, convert or terminate the derivative security;

- Acquisitions or dispositions of equity securities involving a *bona fide* gift or a transfer by will or the laws of descent and distribution;
- Acquisitions or dispositions of equity securities pursuant to a domestic relations order;
- Sales or other dispositions of equity securities compelled by the laws or other requirements of an applicable jurisdiction; and
- Acquisitions or dispositions of equity securities in connection with a merger, acquisition, divestiture or similar transaction occurring by operation of law.[87]

Section 306(a)(3) of the Act[88] permits us to provide appropriate exemptions from the statutory trading prohibition, citing examples of transactions eligible for exemption such as purchases pursuant to an automatic dividend reinvestment program or purchases or sales made pursuant to an advance election. These examples reflect transactions that occur automatically, are made pursuant to an advance election or are otherwise outside the control of the director or executive officer. The exemptions that we originally proposed and are adopting embody one or both of these characteristics. The additional exemptions that we are adopting also reflect these characteristics.

Compensatory grants and awards of equity securities during a blackout period pursuant to a plan that, by its terms, provides for grants and awards to be made to directors and executive officers automatically and specifies the terms and conditions of the grants or awards are outside the control of the directors and executive officers and do not present the concerns that Section 306(a) is intended to remedy. Similarly, an exercise, conversion or termination of a derivative security written or acquired by a director or executive officer before the blackout period in question and while not aware of the actual or approximate beginning or ending dates of the blackout period is a transaction that is outside the control of the director or executive officer where the derivative security either, by its terms, may be exercised, converted or terminated only on a fixed date, or is exercised, converted or terminated by a counterparty where the director or executive officer does not exercise any influence on the counterparty with respect to whether or when to exercise, convert or terminate the derivative security.

The exemption for *bona fide* gifts and acquisitions or dispositions of equity securities by will or the laws of descent and distribution is modeled on a similar exemption under Section 16 of the Exchange Act.[89] The exemption for acquisitions or dispositions pursuant to a domestic relations order is modeled on the exemption in Exchange Act Rule 16a–12.[90]

The exemption for sales or other dispositions of equity securities compelled by the laws or other requirements of an applicable jurisdiction addresses a category of involuntary transactions that do not provide the opportunity for improper self-dealing or present the unfairness Section 306(a) was designed to address. Finally, the exemption for acquisitions or dispositions of equity securities in connection with a merger, acquisition, divestiture or similar transaction occurring by operation of law is intended to cover an exchange of equity securities affecting substantially all of an entity's equity security holders that occurs upon a statutory merger, acquisition, divestiture or similar transaction that closes during a blackout period.

5. Blackout Period

Section 306(a)(4)(A) of the Act defines the term ''blackout period'' to mean any period of more than three consecutive business days during which the ability of not fewer than 50% of the participants or beneficiaries under all individual account plans maintained by an issuer to purchase, sell or otherwise acquire or transfer an interest in any equity security of the issuer held in such an individual account plan is temporarily suspended by the issuer or by a fiduciary[91] of the plan. In the Proposing Release, we solicited comment on whether a trading suspension of three business days or less should be considered a ''blackout period'' for purposes of the statute.

Several commenters opposed expanding the definition of the term ''blackout period'' to encompass periods of three business days or less. One commenter noted that the specific statutory language providing this standard had resulted from extensive discussions among policymakers and representatives of the voluntary employer-provided retirement system, and that blackout periods of three business days or less do not significantly impact the rights of plan participants and beneficiaries.[92] Two commenters requested that Regulation BTR be consistent with the rules under Section 306(b) of the Act adopted by the Department of Labor (the ''DOL Rules''), so that issuers are not subject to different blackout period rules.[93] Two commenters noted that because there may be unforeseen technical problems or other emergencies that could result in unscheduled temporary trading suspensions lasting one or two business days which would not be subject to the advance notice requirement of the DOL Rules, it would be impracticable to comply with Section 306(a) of the Act in these circumstances.[94]

Although Regulation BTR retains the ''more than three consecutive business days'' language in its definition of the term ''blackout period,'' we remain concerned that the problems Section 306(a) is intended to address may not be limited to blackout periods that last longer than three consecutive business days. A sharp decline in the value of an issuer's equity securities can take place in a single day, and, if that decline coincides with a temporary trading suspension in the issuer's pension plans, it is still unfair that directors and executive officers may be able to dispose of the equity securities that they acquired in connection with service or employment as a director or executive officer while rank-and-file employees are precluded from selling issuer equity securities in their individual plan accounts. While most of these temporary trading suspensions are likely the result of unforeseeable technical problems or other emergencies, we are mindful that, given the requirements of the statute, issuers and plan administrators may be motivated to structure blackout periods to last three business days or less. We would view any such efforts to

[87] *See* new Rules 101(c)(4)–(9) of Regulation BTR [17 CFR 245.101(c)(4)–(9)].

[88] 15 U.S.C. 7244(a)(3).

[89] *See* Exchange Act Rule 16b–5 [17 CFR 240.16b–5].

[90] 17 CFR 240.16a–12.

[91] For purposes of the Act and Regulation BTR, a plan administrator will be considered a ''fiduciary'' of the plan even if it has invoked the rules under Section 404(c) of the Employment Retirement Income Security Act of 1974 (''ERISA'') [29 U.S.C. 1104(c)] to avoid liability for losses in participant or beneficiary accounts where participants and beneficiaries are provided an opportunity to exercise control over the assets in their individual accounts and are given an opportunity to choose from a broad range of investments.

[92] *See* the PSCA Letter.

[93] *See* the ACB Letter and the PWC Letter.

[94] *See* the ACB Letter and the Letter dated December 16, 2002 of The ERISA Industry Committee (the ''ERIC Letter'').

circumvent Section 306(a) as potential violations of Regulation BTR. We will continue to consider these issues, to attempt to ascertain whether blackout periods of three business days or less are or may become a concern and to talk to the Department of Labor about possible solutions.

(a) *Individual Account Plan.*

New Rule 100(j) of Regulation BTR [95] sets forth the definition of the term ''individual account plan'' for purposes of Section 306(a) of the Act. As specified in Section 306(a)(5) of the Act,[96] this definition is based on Section 3(34) of ERISA.[97] This definition encompasses a variety of pension plans, including Section 401(k) plans, profit-sharing and savings plans, stock bonus plans and money purchase pension plans.

As specified in the statute, the definition excludes a one-participant retirement plan.[98] In addition, we have modified the definition to exclude pension plans, including deferred compensation plans, in which participation is limited to directors of the issuer. In the case of a temporary trading suspension in issuer equity securities in such a plan, the unfairness of directors and executive officers being able to trade their equity securities while an issuer's employees may not does not exist.[99]

(b) *Blackout Period.*

New Rule 100(b) of Regulation BTR [100] contains the definition of the term ''blackout period'' as clarified to achieve the purposes of Section 306(a) of the Act. The new rule makes clear that, in determining whether a temporary trading suspension in issuer equity securities constitutes a ''blackout period,'' the individual account plans to be considered are individual account plans maintained by an issuer that permit participants or beneficiaries located in the United States to acquire or hold equity securities of the issuer. This includes individual account plans that:

- Permit participants or beneficiaries to invest their plan contributions in issuer equity securities;
- Include an ''open brokerage window'' that permits participants or beneficiaries to invest in the equity securities of any publicly-traded company, including the issuer;
- Match employee contributions with issuer equity securities; or
- Reallocate forfeitures that include issuer equity securities to the remaining plan participants.

This would include such an individual account plan, whether or not the plan actually contains equity securities of the issuer at the time of the temporary trading suspension and related determination.[101] In addition, new Rule 100(b)(3)(i) of Regulation BTR [102] provides that, for purposes of determining the individual account plans maintained by the issuer, the rules under Section 414(b), (c), (m) and (o) of the Internal Revenue Code [103] with respect to entities treated as a single employer are to be applied.

Two commenters questioned whether all individual account plans maintained by an issuer that permit participants or beneficiaries located in the United States to acquire or hold equity securities of the issuer should be included in the percentage test for determining whether a temporary trading suspension constitutes a ''blackout period.'' [104] These commenters noted that, as proposed, the 50% test would take into account any individual account plan (wherever located) maintained by an issuer that permits any participants or beneficiaries located in the United States to acquire or hold issuer equity securities. Thus, even though an individual account plan may be maintained outside the United States, if even a single participant or beneficiary was located in the United States, all of the participants or beneficiaries in the plan would have to be taken into account under the 50% test. One commenter asserted that although foreign issuers may have a small number of U.S. employees participating in their pension plans maintained outside the United States, because these issuers may not keep records of such participation (because the plans are not subject to ERISA), to avoid confusion and inaccurate calculations the 50% test should not apply to these plans.[105]

We believe that a clarification is warranted. Accordingly, new Rule 100(b)(3)(ii) of Regulation BTR [106] excludes an individual account plan maintained outside of the United States primarily for the benefit of nonresident aliens from the determination of whether a temporary trading suspension constitutes a ''blackout period.'' [107] This should focus the determination of whether a blackout period will occur on those individual account plans that are primarily for the benefit of participants and beneficiaries located in the United States. Because ERISA applies to any ''individual account plan'' that is primarily for the benefit of U.S. participants or beneficiaries and Section 404(b) of ERISA [108] provides that the indicia of ownership of the assets of plans subject to ERISA may not be maintained outside the jurisdiction of the United States, we do not believe that this modification is inconsistent with the objectives of Section 306(a).

(c) *Determining Participants and Beneficiaries.*

Once an issuer has identified the relevant individual account plans, it must determine whether the temporary suspension of trading in its equity securities affects 50% or more of the participants or beneficiaries under these plans. This is accomplished by comparing the number of participants or beneficiaries located in the United

[95] 17 CFR 245.100(j).

[96] 15 U.S.C 7244(a)(5). Consequently, a temporary trading suspension in issuer equity securities in an individual account plan that is a pension plan as defined in ERISA may trigger the Section 306(a) trading prohibition, whether or not the plan is actually subject to ERISA.

[97] 29 U.S.C. 1002(34). Section 3(2)(A) of ERISA [29 U.S.C. 1002(2)(A)] defines the term ''pension plan'' to mean ''any plan, fund, or program . . . established or maintained by an employer or an employee organization, or by both, to the extent that by its express terms or as a result of surrounding circumstances such plan, fund, or program (i) provides retirement income to employees, or (ii) results in a deferral of income by employees for periods extending to the termination of covered employment or beyond, regardless of the method of calculating the contributions made to the plan, the method of calculating the benefits under the plan or the method of distributing benefits from the plan.''

[98] *See* Section 306(a)(5) of the Act.

[99] This change was made in response to a comment in the Letter dated December 13, 2002 of the Investment Company Institute (the ''ICI Letter''). We have made this exclusion applicable to all issuers, not just investment companies, because we believe that it is unnecessary to include director-only plans within the scope of the rule, whether or not the issuer is an investment company.

[100] 17 CFR 245.100(b).

[101] Thus, a temporary trading suspension applicable to such an individual account plan in which no issuer equity securities are actually held by plan participants or beneficiaries will trigger a determination of whether a ''blackout period'' will occur in that plan. Similarly, an individual account plan maintained by an issuer that permits participants or beneficiaries to acquire or hold equity securities of the issuer, whether or not the plan actually contains equity securities of the issuer at the time of the determination, will be taken into account in determining whether a temporary trading suspension in a different plan constitutes a ''blackout period.''

[102] 17 CFR 245.100(b)(3)(i).

[103] 26 U.S.C. 414(b), (c), (m) and (o). Section 414(b) provides that, for purposes of various provisions of the Internal Revenue Code, all employees of all corporations that are members of a ''controlled group'' of corporations are to be treated as employed by a single employer. Section 414(c) provides ''single-employer'' treatment for certain groups of partnerships and proprietorships under common control, while Section 414(m) provides ''single-employer'' treatment for organizations that provide services for one another.

[104] *See* the ERIC Letter and the S&C Letter.

[105] *See* the S&C Letter.

[106] 17 CFR 245.100(b)(3)(ii).

[107] This type of employee benefit plan is excluded from the coverage provisions of ERISA. *See* Section 4(b)(4) of ERISA [29 U.S.C. 1003(b)(4)].

[108] 29 U.S.C. 1104(b).

States who are subject to the temporary trading suspension in issuer equity securities to the number of participants or beneficiaries located in the United States under all individual account plans maintained by the issuer.[109] In the case of a domestic issuer, where this percentage is 50% or more the temporary trading suspension constitutes a ''blackout period,'' so that the Section 306(a) trading prohibition applies to the issuer's directors and executive officers.

We recognize that it may be difficult to determine the number of participants and beneficiaries in an individual account plan because participants and beneficiaries continuously enter and leave such plans. For example, newly eligible employees regularly enter plans, terminating and retiring employees regularly leave plans, beneficiaries of deceased employees frequently acquire benefit rights under plans and employees commonly enter and leave plans as a result of acquisitions and divestitures.[110] On any day, it may be difficult for an issuer to know precisely how many participants and beneficiaries are then covered by all of its individual account plans. As a result, issuers will need to apply the 50% test on the basis of estimates.

For purposes of determining the number of participants and beneficiaries in an individual account plan, commenters suggested a variety of ways to establish a reasonably accurate estimate.[111] One commenter suggested that the determination be made using data as of any convenient date within the 12-month period preceding the start of the temporary trading suspension.[112] We believe that this approach strikes the proper balance between ensuring that reasonably accurate data is used to make the required calculation and minimizing the burden on issuers. New Rule 100(b)(4)(i) of Regulation BTR[113] provides that an issuer may use plan census data as of any date within the 12-month period preceding the beginning date of the temporary trading suspension in question (such as the last day of the most recently completed fiscal year) to determine the number of participants or beneficiaries in its individual account plans. However, where there has been a significant change in participation in an individual account plan since the date selected (for example, because of a merger or divestiture), an issuer is required to use plan census data as of the most recent practicable date that reflects such change (for example, the most recently completed fiscal quarter or month for that plan). This should provide adequate flexibility to issuers to determine the number of participants or beneficiaries in their individual account plans using reasonably accurate and available data.

In addition, new Rule 100(b)(4)(ii) of Regulation BTR[114] provides that, in making the calculation, issuers may aggregate participants or beneficiaries under their individual account plans without regard to overlapping plan participation. This should alleviate the burden that might otherwise arise where individual employees participate in more than one individual account plan maintained by an issuer. Under this provision, an issuer is permitted to calculate the aggregate number of participants and beneficiaries under each of its individual account plans, even if an individual who participates in multiple plans is counted with respect to each plan in which he or she participates.

(d) *Foreign Private Issuers.*

In the case of a foreign private issuer, we proposed a concurrent second calculation to be applied to determine if a temporary trading suspension in issuer equity securities in the individual account plans maintained by the issuer constitutes a ''blackout period'' for purposes of Section 306(a) of the Act. This calculation would have compared the number of participants or beneficiaries located in the United States who are subject to the temporary trading suspension in issuer equity securities to the number of participants or beneficiaries under all individual account plans maintained by the issuer worldwide.[115] Where this percentage exceeded 15% and the concurrent 50% test also was met, the Section 306(a) trading prohibition would have applied to the foreign private issuer's directors and executive officers.

However, commenters expressed concern that, as proposed, the 15% test would not operate as intended.[116] These commenters noted that many foreign private issuers do not maintain pension plans that meet the ERISA definition of an ''individual account plan,'' other than the plans they maintain for their U.S. employees. In particular, they noted that outside the United States employees customarily participate in defined benefit pension plans, rather than individual account plans. Because the proposed 15% test was based on the percentage of an issuer's employees who participate in individual account plans, an issuer maintaining individual account plans only in the United States that were subject to a temporary trading suspension in issuer equity securities almost always would meet the test, even where the number of participants or beneficiaries in those plans was insignificant. In addition, one commenter indicated that many foreign issuers do not maintain centralized information on the types of plans they maintain or the numbers of participants or beneficiaries under the plans subject to the laws of jurisdictions other than the United States.[117]

These commenters suggested that the appropriate balance between protecting U.S. participants and beneficiaries and accommodating the interests of foreign private issuers with a limited U.S. presence could be achieved by comparing the number of participants and beneficiaries located in the United States who are subject to the temporary trading suspension in issuer equity securities to the number of employees of the issuer worldwide. While we agree with this suggestion, we are mindful that, in some situations, such a test may frustrate the purposes of Section 306(a) where a significant number of U.S. employees are affected by a temporary trading suspension in issuer equity securities, even though that number may not represent at least 15% of a foreign private issuer's total number of employees. Accordingly, we are modifying the separate calculation for foreign private issuers in new Rule 100(b)(2) of Regulation BTR[118] to provide that if the number of participants or beneficiaries located in the United States in individual account plans maintained by a foreign private issuer who are affected by a temporary trading suspension in issuer equity securities either exceeds 15% of the total number of employees of the issuer and its consolidated subsidiaries or 50,000 affected participants and beneficiaries[119] and the concurrent 50% test is satisfied, the Section 306(a) trading prohibition will apply to the issuer's directors and executive officers.

[109] *See* new Rule 100(b)(1) of Regulation BTR.

[110] *See* the ERIC Letter.

[111] *See*, for example, the Letter dated December 16, 2002 of Computer Sciences Corporation, the PSCA Letter and the PWC Letter.

[112] *See* the ABA Letter.

[113] 17 CFR 245.100(b)(4)(i).

[114] 17 CFR 245.100(b)(4)(ii).

[115] *See* proposed Exchange Act Rule 100(b)(2).

[116] *See* the ABA Letter; the Cleary Letter; the S&C Letter and the Letter dated December 16, 2002 of Shearman & Sterling.

[117] *See* the S&C Letter.

[118] 17 CFR 245.100(b)(2).

[119] We arrived at this number after examining the number of employees (including the number of employees based in the United States) of several foreign private issuers, applying the 15% calculation to these issuers and balancing the objectives of Section 306(a) of the Act with the interests of foreign private issuers.

Under new Exchange Act Rule 100(b)(2):

• If the number of participants and beneficiaries located in the United States in individual account plans maintained by a foreign private issuer who are subject to a temporary trading suspension in issuer equity securities exceeds 15% of the number of employees of the issuer worldwide (and the concurrent 50% test is satisfied), the issuer will be considered to have a sufficient presence in the United States for purposes of applying the Section 306(a) trading prohibition to the issuer's directors and executive officers.

• If the number of participants and beneficiaries located in the United States in individual account plans maintained by a foreign private issuer who are subject to a temporary trading suspension in issuer equity securities does not exceed 15% of the number of employees of the issuer worldwide but exceeds 50,000 participants and beneficiaries (and the concurrent 50% test is satisfied), the issuer will be considered to have a sufficient presence in the United States for purposes of applying the Section 306(a) trading prohibition to the issuer's directors and executive officers.

• If the number of participants and beneficiaries located in the United States in individual account plans maintained by a foreign private issuer who are subject to a temporary trading suspension in issuer equity securities does not exceed 15% of the issuer's employees worldwide and is 50,000 or less participants and beneficiaries (even if the concurrent 50% test is satisfied), the issuer's presence in the United States will be considered sufficiently small so that its directors and executive officers will not be subject to the Section 306(a) trading prohibition.

The application of these principles is illustrated by the following examples:

• *Example 1.* Company X is a foreign private issuer with 100,000 employees worldwide. 30,000 employees located in the United States participate in the company's two U.S. pension plans, which are individual account plans. A fiduciary of one of the U.S. pension plans temporarily suspends the ability of all plan participants to trade in issuer equity securities through their plan accounts. This temporary trading suspension affects 16,000 participants in the U.S. plans. Since the number of participants located in the United States in individual account plans maintained by the issuer who are subject to the temporary trading suspension comprises 50% or more of the total number of participants located in the United States in individual account plans maintained by the issuer (16,000/30,000), and since the number of participants located in the United States in individual account plans maintained by the issuer who are subject to the temporary trading suspension represents more than 15% of the issuer's employees worldwide (16,000/100,000), the temporary trading suspension is a ''blackout period'' for purposes of Section 306(a) of the Act and the statutory trading prohibition applies to the issuer's directors and executive officers.

• *Example 2.* Company X is a foreign private issuer with 1,000,000 employees worldwide. 100,000 employees located in the United States participate in the company's two U.S. pension plans, which are individual account plans. A fiduciary of one of the U.S. pension plans temporarily suspends the ability of all plan participants to trade in issuer equity securities through their plan accounts. This temporary trading suspension affects 60,000 participants in the U.S. plans. Since the number of participants located in the United States in individual account plans maintained by the issuer who are subject to the temporary trading suspension comprises 50% or more of the total number of participants located in the United States in individual account plans maintained by the issuer (60,000/100,000), and since the number of participants located in the United States in individual account plans maintained by the issuer who are subject to the temporary trading suspension exceeds 50,000, the temporary trading suspension is a ''blackout period'' for purposes of Section 306(a) of the Act even though the 60,000 participants located in the United States in individual account plans maintained by the issuer who are subject to the temporary trading suspension represent less than 15% of the issuer's employees worldwide (150,000/1,000,000). Consequently, the statutory trading prohibition applies to the issuer's directors and executive officers.

• *Example 3.* Company X is a foreign private issuer with 100,000 employees worldwide. 6,000 employees located in the United States participate in the company's two U.S. pension plans, which are individual account plans. A fiduciary of one of the U.S. pension plans temporarily suspends the ability of all plan participants to trade in issuer equity securities through their plan accounts. This temporary trading suspension affects 4,000 participants in the U.S. plans. Although the number of participants located in the United States in individual account plans maintained by the issuer who are subject to the temporary trading suspension is 50% or more of the total number of participants located in the United States in individual account plans maintained by the issuer (4,000/6,000), because this number represents 15% or less of the issuer's employees worldwide (4,000/100,000) and is less than 50,000 participants, the temporary trading suspension is not a ''blackout period'' for purposes of Section 306(a) of the Act. Consequently, the statutory trading prohibition does not apply to the issuer's directors and executive officers.

(e) *Exceptions to Definition of Blackout Period.*

Section 306(a)(4)(B) of the Act [120] expressly excludes two types of temporary trading suspensions from the definition of the term ''blackout period.'' These exceptions are for:

• a regularly scheduled period in which the participants and beneficiaries may not purchase, sell or otherwise acquire or transfer an interest in any equity security of an issuer, if such period is:

—Incorporated into the individual account plan; and

—Timely disclosed to employees before they become participants under the individual account plan or as a subsequent amendment to the plan;[121] and

• any temporary trading suspension that would otherwise be a ''blackout period'' that is imposed solely in connection with persons becoming participants or beneficiaries, or ceasing to be participants or beneficiaries, in an individual account plan by reason of a corporate merger, acquisition, divestiture or similar transaction involving the plan or plan sponsor.[122]

New Rule 102 of Regulation BTR [123] addresses the application of these exceptions.[124] New Rule 102(a) of Regulation BTR [125] clarifies the exception for regularly scheduled trading suspensions. It provides that the requirement that the regularly scheduled period be incorporated into the individual account plan may be satisfied by including a description of the regularly scheduled trading suspension in issuer equity securities, including the suspension's frequency and duration and the plan transactions to be suspended or otherwise affected, in either the official plan documents or other documents or instruments that govern plan operations. In the latter case, these documents or instruments may include an ERISA Section 404(c) notice or an advance notice included in either the plan's summary plan description or any other official plan communication.

The new rule also provides that disclosure of the regularly scheduled trading suspension will be considered timely if the employee is notified of the trading suspension at any time prior to, or within 30 calendar days after, the employee's formal enrollment in the

[120] 15 U.S.C. 7244(a)(4)(B).

[121] *See* Section 306(a)(4)(B)(i) of the Act [15 U.S.C. 7244(a)(4)(B)(i)].

[122] *See* Section 306(a)(4)(B)(ii) of the Act [15 U.S.C. 7244(a)(4)(B)(ii)].

[123] 17 CFR 245.102.

[124] These clarifications are necessary to resolve ambiguities that might otherwise require literal compliance with the conditions of the exceptions in order to avoid having the described temporary trading suspensions be ''blackout periods'' for purposes of Section 306(a) of the Act.

[125] 17 CFR 245.102(a).

plan, or, in the case of a subsequent amendment to the plan, within 30 calendar days after adoption of the amendment. The new rule provides that the notice may be in any graphic form that is reasonably accessible to the intended recipient.[126]

Some commenters indicated that the 30-day notice requirement would present a problem for existing plans with a regularly scheduled trading suspension.[127] These commenters noted that ERISA typically requires delivery of information to a new plan participant within 90 days after enrollment in the plan, and that an issuer that previously provided notice of a regularly scheduled trading suspension in a summary plan description within this 90-day period would not qualify for the exception. To avoid this problem, they suggested that we establish a transition period during which issuers could cure any past failures to satisfy the 30-day notice requirement. Because we believe that the adoption of Regulation BTR should not penalize an issuer retroactively, we will consider an issuer to have satisfied the advance notice requirement of new Rule 102(a)(2) with respect to an individual account plan that includes a regularly scheduled trading suspension that is maintained by an issuer on January 26, 2003, the effective date of Section 306(a) of the Act, if the issuer previously provided the information described in the rule in the documents or instruments required by ERISA to be provided to plan participants within the time period authorized by ERISA.[128]

In the case of a temporary trading suspension in issuer equity securities imposed in connection with a merger, acquisition, divestiture or similar transaction, new Rule 102(b) of Regulation BTR[129] provides that the temporary suspension will not constitute a ''blackout period'' for purposes of Section 306(a) if its principal purpose is to enable individuals to become participants or beneficiaries in an individual account plan by reason of the transaction, or to terminate participation in the plan, even though the suspension also is used to effect other administrative actions that are incidental to the admission or withdrawal of plan participants or beneficiaries. In addition, the new rule clarifies that the exception is available solely if the persons becoming participants or beneficiaries are not permitted to participate in the same class of equity securities after the merger, acquisition, divestiture or similar transaction as before the transaction. This will limit the scope of the exception to temporary trading suspensions affecting persons employed by or affiliated with the acquired or divested entity.

6. Remedies

As we discussed in the Proposing Release, Section 306(a) of the Act contains two distinct sets of remedies. A violation of the statutory trading prohibition in Section 306(a)(1) of the Act is treated as a violation of the Exchange Act and subject to all resulting sanctions, including Commission enforcement action.[130] In addition, where a director or executive officer realizes a profit from a prohibited transaction during a blackout period, Section 306(a)(2) of the Act[131] permits an issuer, or a security holder of the issuer on its behalf, to bring an action to recover that profit.[132]

Under the latter provision, an issuer, or a security holder on its behalf, may initiate an action only if a director or executive officer realized a profit as a result of a prohibited purchase, sale or other acquisition or transfer of an equity security during a blackout period. As under Section 16(b) of the Exchange Act, this concept of ''realized profits'' means that the director or executive officer received a direct or indirect pecuniary benefit from the transaction.[133] Although we did not propose a specific method for calculating the amount recoverable by an issuer under Section 306(a)(2) in the Proposing Release, we suggested several possible ways to calculate recoverable profits and solicited comment on these alternatives, as well as any other method consistent with the purposes of the statute.

Some commenters, acknowledging the potential complexity of the calculation, encouraged us not to provide a comprehensive rule.[134] One commenter suggested that the calculation be left to the courts to determine on a case-by-case basis or, alternatively, that we establish a specific formula or guidelines for use in enforcement and private civil actions.[135]

In the Proposing Release, one of the potential methods to calculate profits on which we solicited comment was based on the difference between the actual amount paid or received by a director or executive officer as a result of the purchase, sale or other acquisition or transfer of an equity security during a blackout period and the market value of the issuer's equity securities on the first date after the end of the blackout period.[136] One commenter endorsed this approach as the appropriate measure of the profit recoverable in a private action for a violation of the Section 306(a) trading prohibition.[137] We believe that this approach has merit, both in terms of its simplicity and its adherence to the statute's purposes. Section 306(a)(2) seeks to equalize the treatment of corporate executives and rank-and-file employees with respect to their opportunity, during a pension plan blackout period, to engage in transactions in issuer equity securities that were acquired in connection with their service to, or employment with, the issuer. Since a plan participant or beneficiary may not engage in a transaction in issuer equity securities through his or her plan account until the blackout period has ended, the statute similarly restricts directors and executive officers. This profit recovery measure focuses on the difference between the amount that a director or executive officer actually paid or received in the transaction and the amount he or she would have paid or received had the transaction been conducted after the end of the blackout period.

To provide guidance to the courts in Section 306(a)(2) private actions against directors and executive officers who have violated the statutory trading prohibition, new Rule 103(c) of Regulation BTR[138] provides that:

- Where a transaction involves a purchase, sale or other acquisition or transfer (other than a grant, exercise, conversion or termination of a derivative security) of an equity security of the issuer that is registered pursuant to Section 12(b) or 12(g) of the Exchange Act[139] and listed on a national securities exchange or listed in an automated inter-dealer quotation system of a national securities association, profit is to be measured by comparing the difference between the amount paid or received for the equity security on the date of the transaction during the blackout period and the average market

[126] *See* new Rule 102(a)(2) of Regulation BTR [17 CFR 245.102(a)(2)].

[127] *See* the ABA Letter, the ERIC Letter and the S&C Letter.

[128] *See* Section 104(b) of ERISA [29 U.S.C. 1024(b)].

[129] 17 CFR 245.102(b).

[130] *See* Sections 3(b)(1) and 306(a)(1) of the Act [15 U.S.C. 7202(b)(1) and 7244(a)(1)]. *See* also the Proposing Release at Section II.B.6.a.

[131] 15 U.S.C. 7244(a)(2).

[132] 15 U.S.C. 7244(a)(2).

[133] *See* Exchange Act Rule 16a–1(a)(2)(i) [17 CFR 240.16a–1(a)(2)(i)]. *See* also *Feder* v. *Frost,* 220 F.3d 29, 34 (2d Cir. 2000).

[134] *See* the ACB Letter and the Cleary Letter.

[135] *See* the ACB Letter.

[136] *See* the Proposing Release, at Section II.B.6.c.

[137] *See* the ABA Letter.

[138] 17 CFR 245.103(c).

[139] 15 U.S.C. 78l(b) or (g).

price of the equity security calculated over the first three trading days after the ending date of the blackout period.

• Where a transaction is not otherwise described in the preceding paragraph, profit is to be measured in a manner that is consistent with the objective of identifying the amount of any gain realized or loss avoided as a result of the transaction taking place during the blackout period rather than taking place outside of the blackout period.

To mitigate the effect of large fluctuations in the market price of an issuer's equity securities after a blackout period and deter attempts to manipulate this market price, new Rule 103(c)(1) of Regulation BTR [140] uses a three-day average trading price to determine the amount that a director or executive officer would have paid or received if the transaction had occurred after the end of the blackout period. New Rule 103(c)(2) of Regulation BTR [141] addresses transactions that do not lend themselves to a simple calculation (such as derivative securities transactions, transactions involving an issuer that is required to file reports under Section 15(d) of the Exchange Act and transactions involving an issuer that has filed a registration statement for an initial public offering that has not yet become effective). This rule reflects a pragmatic approach that should permit consideration of equitable factors in determining the amount recoverable in a private action consistent with the purposes of the Section 306(a) trading prohibition. New Rule 103(c)(3) of Regulation BTR [142] provides that the calculation methods with respect to a private action under Section 306(a)(2) do not limit in any respect the authority of the Commission to seek or determine remedies as the result of a transaction taking place in violation of Section 306(a)(1) of the Act.

This operation of the new rule is illustrated by the following examples:

• *Example 1:* The XYZ Company Section 401(k) plan imposes a temporary trading suspension on plan participants and beneficiaries from December 1st through the following January 3rd that is a ''blackout period'' for purposes of Section 306(a). Director A acquires 1,000 shares of XYZ Company common stock in connection with his or her service as a director on December 15th for $10.00. Between January 6th and 8th, the first three trading days after the end of the blackout period, XYZ Company common stock trades at an average price of $12.00 per share. Director A has ''realized'' a profit of $2000 that is recoverable under Section 306(a)(2).

• *Example 2:* The XYZ Company Section 401(k) plan imposes a temporary trading suspension on plan participants and beneficiaries from December 1st through the following January 3rd that is a ''blackout period'' for purposes of Section 306(a). Director A acquires 1,000 shares of XYZ Company common stock in connection with his or her service as a director on December 15th for $10.00. Between January 6th and 8th, the first three trading days after the end of the blackout period, XYZ Company common stock trades at an average price of $8.00 per share. There is no recoverable profit under Section 306(a)(2), as Director A received no price advantage over plan participants from purchasing the share of XYZ Company common stock during the blackout period.

• *Example 3:* The XYZ Company Section 401(k) plan imposes a temporary trading suspension on plan participants and beneficiaries from December 1st through the following January 3rd that is a ''blackout period'' for purposes of Section 306(a). Director A disposes of 1,000 shares of XYZ Company common stock previously acquired in connection with his or her service as a director on December 15th for $20.00. Between January 6th and 8th, the first three trading days after the end of the blackout period, XYZ Company common stock trades at an average price of $12.00 per share. Director A has ''realized'' a profit of $8000 that is recoverable under Section 306(a)(2).

• *Example 4:* The XYZ Company Section 401(k) plan imposes a temporary trading suspension on plan participants and beneficiaries from December 1st through the following January 3rd that is a ''blackout period'' for purposes of Section 306(a). Director A disposes of 1,000 shares of XYZ Company common stock previously acquired in connection with his or her service as a director on December 15th for $20.00. Between January 6th and 8th, the first three trading days after the end of the blackout period, XYZ Company common stock trades at an average price of $25.00 per share. There is no recoverable profit, as Director A received no price advantage over plan participants from selling the share of XYZ Company common stock during the blackout period.

Without regard to whether any amount is recoverable under Section 306(a)(2), in each example Director A has violated Section 306(a)(1) and, as a result, is subject to sanctions, including Commission enforcement action.

7. Notice

Section 306(a)(6) of the Act [143] requires an issuer to provide timely notice to its directors and executive officers and to the Commission of the imposition of a blackout period that triggers the trading prohibition of Section 306(a) of the Act. New Rule 104 of Regulation BTR [144] specifies how issuers must satisfy this notice requirement. As discussed in the Proposing Release, an issuer's failure to provide notice will not preclude a Commission enforcement action for a violation of Section 306(a)(1) of the Act or a private action to recover profits under Section 306(a)(2) of the Act. In addition, an issuer's failure to provide notice, whether or not a director or executive officer subsequently violates the Section 306(a) trading prohibition, may result in a Commission enforcement action against the issuer for violating the Exchange Act.[145]

(a) *Content of Notice.*

New Rule 104(b)(1) of Regulation BTR [146] sets forth the content requirements for the notice required by Section 306(a)(6) of the Act. With one exception, these content requirements track the requirements described in the Proposing Release. New Rule 104(b)(1)(iv) of Regulation BTR [147] requires that the notice specify the length of the blackout period. As proposed, this requirement contemplated that the notice specify the actual or expected beginning and ending dates of the blackout period. One commenter indicated that many issuers would find it difficult to project in advance the beginning and ending dates of a blackout period, noting that a wide range of events (such as problems with plan records or recordkeeper, extensive document reviews and data reconciliation, required modifications to systems and software and the like) could affect these dates.[148] As a result, the dates included in the notice could be missed and issuers would have to incur additional costs to furnish updated notices. To avoid this potential problem, this commenter speculated that issuers would be likely to establish longer blackout periods, thereby unnecessarily prolonging the inability of plan participants and beneficiaries, as well as directors and executive officers, to engage in transactions involving issuer equity securities. To address this concern, the commenter suggested that issuers be permitted to identify in the notice a range of possible dates during which the blackout period might begin or end.

We recognize the difficulty of predicting specific beginning and ending dates for a blackout period well in advance of when the blackout will occur. We also note that the DOL Rules have been modified to permit a more flexible approach in describing the

[140] 17 CFR 245.103(c)(1).

[141] 17 CFR 245.103(c)(2).

[142] 17 CFR 245.103(c)(3).

[143] 15 U.S.C. 7244(a)(6).

[144] 17 CFR 245.104.

[145] *See* Section 3(b)(1) of the Act.

[146] 17 CFR 245.104(b)(1).

[147] 17 CFR 245.104(b)(1)(iv).

[148] *See* the ICI Letter.

length of an impending pension plan blackout period.[149] We are persuaded that the rules should afford issuers some flexibility in disclosing the beginning and ending dates of a blackout period in the required notice. As adopted, new Rule 104(b)(1)(iv) permits the length of a blackout period to be specified using either the actual or expected beginning date and ending date of the blackout period, or the calendar week or weeks during which the blackout period is expected to begin and end, provided that during such week or weeks information as to whether the blackout period has begun or ended is readily available, without charge, to affected directors and executive officers (such as via a toll-free telephone number or access to a specified web site) and the notice describes how to access the information.[150] New Rule 104(b)(1)(iv) further permits the length of the blackout period to be described in the notice to the Commission using the calendar week or weeks during which the blackout period is expected to begin and end, provided that the notice also describes how a security holder or other interested person may obtain, without charge, the actual beginning and ending dates of the blackout period. Under the rule, it is permissible to use a ''week of _____'' beginning date and a ''week of _____'' ending date. It also is permissible to use a specific beginning date and a ''week of _____'' ending date, or the converse. For purposes of the rule, a calendar week is defined to mean a seven-day period beginning on Sunday and ending on Saturday.[151]

As discussed in the Proposing Release, if an issuer elects to provide the actual or expected beginning and ending dates of a blackout period in the required notice, and either or both of those dates change, the issuer is required to provide directors and executive officers and the Commission with an updated notice identifying the changed date or dates, explaining the reasons for the change in the date or dates and identifying all material changes in the information contained in the prior notice.[152] The updated notice is required to be provided as soon as reasonably practicable.

(b) *Timing of Notice to Directors and Executive Officers.*

As proposed, the required notice to directors and executive officers would have been due at least 15 calendar days in advance of beginning date of a blackout period. However, one commenter noted that while the content requirements of the notice required under Section 306(a) of the Act and the DOL Rules are essentially the same, the proposed timing requirements were very different and would have placed significantly increased reporting and compliance burdens on issuers.[153] This commenter suggested that there be a single triggering event that would harmonize the different notice requirements.

We believe that, to the extent practicable, the notice requirement of Section 306(a)(6) of the Act should be coordinated with the required notice to pension plan participants and beneficiaries and the issuer under the DOL Rules.[154] Consequently, new Rule 104(b)(2) of Regulation BTR[155] provides that the notice to directors and executive officers will be considered timely if an issuer provides it no later than five business days after the issuer receives the notice from the pension plan administrator required by the DOL Rules.[156] If the issuer does not receive such notice, the issuer must provide its notice to directors and executive officers at least 15 calendar days before the actual or expected beginning date of the blackout period. This requirement will ensure that an issuer typically will not be required to provide the notice required by Section 306(a)(6) to its directors and executive officers until it has received notice of an impending blackout period from the pension plan administrator. Notwithstanding this general requirement, new Rule 104(b)(2)(ii) of Regulation BTR[157] provides that advance notice is not required in any case where an unforeseeable event or circumstances beyond the issuer's reasonable control prevent the issuer from providing advance notice to its directors and executive officers.

(c) *Notice to the Commission on Form 8–K.*

To ensure widespread dissemination of information about an impending blackout period, we proposed that issuers file the notice to the Commission required by Section 306(a)(6) of the Act on Form 8–K. The proposed content of this Form 8–K report was the same as the content of the required notice to directors and executive officers. While one commenter supported the use of Form 8–K to provide the required notice to the Commission,[158] some commenters opposed the requirement, arguing that the disclosure would be of limited interest to investors.[159]

One commenter noted that even if a director or executive officer engaged in a transaction in issuer equity securities during a blackout period, an investor who knew of the Form 8–K report would not know whether the securities in question were subject to the Section 306(a) trading prohibition, only that the transaction had taken place during a blackout period.[160] Another commenter suggested that if public disclosure was necessary, an issuer should be permitted to file a copy of the notice given to participants and beneficiaries by the pension plan administrator under the DOL Rules as an exhibit to its periodic report for the fiscal period during which the blackout period began.[161]

We continue to believe that Congress intended for the notice to the Commission to be publicly available to security holders and other interested persons. Consequently, we believe that Form 8–K is an appropriate vehicle for ensuring timely notice to the Commission of a blackout period that triggers the Section 306(a) trading prohibition.

Some commenters expressed concern about the proposed two business days filing requirement for the Form 8–K.[162] One commenter suggested that since the notice will contain the same information that is required in the notice to the issuer under the DOL Rules, a Form 8–K should be required

[149] Comments about the difficulty in projecting in advance the beginning and ending dates of a blackout period were raised with the Department of Labor in response to the interim final rules adopted by the Department of Labor last year under Section 306(b) of the Act. *See* 67 FR 64766. As a result, the Department of Labor modified its rules to permit use of a limited range of dates for purposes of disclosing the beginning and ending dates of a blackout period.

[150] This rule is similar to the DOL Rules.

[151] *See* new Rule 104(b)(1)(iv)(C) of Regulation BTR [17 CFR 245.104(b)(1)(iv)(C)].

[152] *See* new Rules 104(b)(2)(iii) and 104(b)(3)(iii) of Regulation BTR [17 CFR 245.104(b)(2)(iii) and 104(b)(3)(iii)].

[153] *See* the Letter dated December 12, 2002 of Compass Bancshares, Inc.

[154] As enacted under Section 306(b) of the Act, Section 101(i)(2)(B) of ERISA [29 U.S.C. 1021(i)(2)(B)] requires that, at least 30 days in advance of a blackout period, a plan administrator notify affected plan participants and beneficiaries of the impending blackout period. In addition, Section 101(i)(2)(E) of ERISA [29 U.S.C. 1021(i)(2)(E)] requires a plan administrator to timely notify the issuer of the plan securities of the impending blackout period.

[155] 17 CFR 245.104(b)(2).

[156] For purposes of the rule, notice will be considered provided as of the date of mailing, if mailed by first class mail, or as of the date of electronic transmission, if transmitted electronically.

[157] 17 CFR 245.104(b)(2)(ii).

[158] *See* the PWC Letter.

[159] *See* the ABA Letter, the ACB Letter and the Intel Letter.

[160] *See* the ACB Letter.

[161] *See* the ABA Letter.

[162] *See* the ACB Letter and the Intel Letter.

only upon an issuer's receipt of notice from the pension plan administrator.[163] Otherwise, an issuer might learn of an impending blackout period, but not have the necessary information to satisfy the notice requirement. In addition, this commenter noted that requiring a Form 8–K to be filed before an issuer is prepared to communicate with plan participants and beneficiaries about an impending blackout period could result in significant confusion for the participants and beneficiaries and recommended that the issuer be permitted to give notice to the Commission only after it is prepared to give meaningful notice to plan participants and beneficiaries.

As previously discussed, we believe that, to the extent practicable, the required notice under Section 306(a)(6) should be coordinated with the required notice to plan participants and beneficiaries and the issuer under the DOL Rules. Consequently, the instructions to Form 8–K have been revised to provide that the notice to the Commission on Form 8–K must be filed on the same day notice is transmitted to directors and executive officers.[164] This requirement will ensure that, in most situations, an issuer will provide notice of an impending blackout period to its directors and executive officers and to the Commission within five days following receipt of notice of the blackout from the pension plan administrator required by the DOL Rules.

New Rule 104(b)(3)(ii) of Regulation BTR[165] provides that a foreign private issuer subject to Section 306(a) must file as an exhibit to its annual report on Form 20–F or 40–F a copy of each notice provided to directors and executive officers pursuant to Section 306(a)(6) and new Exchange Act Rule 104 during the most recently completed fiscal year, unless the notice previously was provided to the Commission in a report on Form 6–K.[166] A foreign private issuer may make the required disclosure sooner under cover of Form 6–K, and we encourage foreign private issuers to do so.

We proposed to subject registered investment companies to Form 8–K requirements for the sole purpose of meeting their filing obligations under Regulation BTR. Two commenters objected to that proposal, suggesting instead alternative means of providing disclosure about blackout periods.[167] However, because we believe that registered investment companies should be subject to the same filing obligations as other issuers in the infrequent instances where the Form 8–K filing requirement would be triggered,[168] we do not believe it is appropriate to create a filing requirement for registered investment companies that is different from that applicable to other issuers under Regulation BTR. Accordingly, we are adopting the Form 8–K requirement for registered investment companies as proposed.[169]

(d) *Transition Period.*

Section 306(a) of the Act takes effect on January 26, 2003. Consequently, for purposes of Regulation BTR, the notice requirement of Section 306(a)(6) of the Act applies to blackout periods commencing on or after January 26, 2003.

For blackout periods commencing between January 26, 2003 and February 25, 2003 (the date 30 days after the effective date of Section 306(a)), issuers should furnish notice to directors and executive officers as soon as reasonably practicable. This approach is intended to ensure that the statutorily-required notice is provided with respect to blackout periods that commence before February 26, 2003. In no event, however, is notice required for a blackout period that commenced before January 26, 2003 and remains in effect on that date.

In the case of notice to the Commission, new Rules 104(b)(3)(i) and (iii) of Regulation BTR are effective 60 days after publication in the **Federal Register** to allow time for the addition of new Form 8–K Item 11 to the Electronic Data Gathering, Analysis and Retrieval (''EDGAR'') system. In the interim, an issuer may provide the required notice to the Commission by disclosing the information described in Item 11 under Item 5 of Form 10–Q[170] or 10–QSB,[171] ''Other Information,'' in the first quarterly report filed by the issuer after commencement of the blackout period.

III. Paperwork Reduction Act

The new rules and rule and form amendments contain new and affect existing ''collection of information'' requirements within the meaning of the Paperwork Reduction Act of 1995 (''PRA'').[172] The title for the new collection of information is ''Regulation BTR.'' The titles for the collections of information affected by the amendments are ''Form 20–F'' (OMB Control No. 3235–0288), ''Form 40-F'' (OMB Control Number 3235–0381) and ''Form 8–K'' (OMB Control No. 3235–0060). We estimated that preparation and distribution of the notice to directors and executive officers under the new rules would require approximately 2,357 hours and cost approximately $253,075 annually. We also estimated that preparation of current reports on Form 8–K to provide the required notice to the Commission would require approximately 2,490 hours and cost approximately $336,000 annually. The inclusion of the required information in annual reports on Form 20–F was estimated to require approximately 249 hours and cost approximately $33,625 annually, and the inclusion of the required information in annual reports on Form 40–F was estimated to require approximately 28 hours and cost approximately $3,735 annually.

We published a notice requesting comments on the collection of information requirements and submitted requests to the Office of Management and Budget (''OMB'') for approval of the new collection and changes to the existing collections in accordance with the PRA.[173] These requests are pending before the OMB. We did not receive any comments on the PRA analysis contained in the proposing release. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number.

New Regulation BTR clarifies the application and prevents evasion of Section 306(a) of the Sarbanes-Oxley Act. Section 306(a) prohibits the directors and executive officers of an issuer from, directly or indirectly, purchasing, selling or otherwise acquiring or transferring any equity security of the issuer during a pension plan blackout period that prevents plan participants or beneficiaries from engaging in equity securities transactions, if the equity security was acquired in connection with the director's or executive officer's service or employment as a director or executive officer. Section 306(a) also requires an issuer to provide timely notice to its directors and executive officers and to the Commission of the commencement of a blackout period. Regulation BTR specifies the content

[163] *See* the ACB Letter.

[164] *See* revised Instruction B.1 to Form 8–K.

[165] 17 CFR 245.104(b)(3)(ii).

[166] 17 CFR 249.306.

[167] *See* the ICI Letter and the PWC Letter.

[168] For a discussion of the application of Regulation BTR to registered investment companies, see the Proposing Release at Section II.B.1.d.

[169] *See* amended Exchange Act Rules 13a-11(b) and 15d-11(b) [17 CFR 240.13a-11(b) and 240.15d-11(b)].

[170] 17 CFR 249.308a.

[171] 17 CFR 249.308b.

[172] 44 U.S.C. 3501 *et seq.*

[173] 44 U.S.C. 3507(d) and 5 CFR 1320.11.

and timing of this notice. Compliance with the new rules will be mandatory. The information required by the new rules will not be kept confidential.

IV. Cost-Benefit Analysis

Section 306(a) of the Act prohibits directors and executive officers of an issuer from purchasing, selling or otherwise acquiring or transferring any equity security of the issuer during a pension plan blackout period that prevents plan participants or beneficiaries from engaging in equity security transactions, if the equity security was acquired by the director or executive officer in connection with his or her service or employment as a director or executive officer. In addition, Section 306(a) requires an issuer to provide timely notice to its directors and executive officers, and to the Commission, of the imposition of a pension plan blackout period. The statute is intended to restrict the ability of corporate insiders to trade in the equity securities of an issuer at a time when a substantial portion of the issuer's employees are unable to engage in transactions involving equity securities of the issuer through their individual pension plan accounts.

The new rules clarify the application of Section 306(a) and prevent evasion of its statutory trading prohibition. We recognize that any implementation of the Sarbanes-Oxley Act likely will result in costs as well as benefits and have an effect on the economy. We are sensitive to the costs and benefits of the new rules that specify the content and timing of the notice that issuers are required to provide to their directors and executive officers and that mandate the required notice to the Commission to be provided on a Form 8–K or, in the case of foreign private issuers, in their annual reports on Form 20–F or 40-F. We discuss these costs and benefits below.

A. Benefits

Section 306(a) and the new rules have several important benefits. By restricting the ability of directors and executive officers to trade in an issuer's equity securities when plan participants are unable to do so, the new rules mitigate the differential opportunities between plan participants and beneficiaries and the directors and executive officers of the issuer with respect to such securities.

The content requirements for the notice contemplated by Section 306(a) will help ensure that directors and executive officers of an issuer have all relevant information about an impending blackout period. This will facilitate their compliance with the statutory trading prohibition. In addition, requiring that notice to the Commission be provided on Form 8–K or, in the case of a foreign private issuer, on Form 20–F or 40–F, will help ensure that an issuer's security holders have notice of an impending blackout period. In turn, this will enable security holders to monitor compliance with the statutory trading prohibition of Section 306(a). These benefits are difficult to quantify.

B. Costs

The costs associated with the new rules are attributable primarily to the statutory requirement to prepare and distribute advance notice of the imposition of a blackout period to directors and executive officers and to the Commission. For purposes of the Paperwork Reduction Act, we estimated the aggregate costs for issuers required to provide this notice to be approximately $625,000 per year and the related burden to be approximately 5,125 hours.[174]

While compliance with Section 306(a)'s trading prohibition is the personal obligation of an issuer's directors and executive officers, it is likely that issuers will incur costs in assisting these individuals in observing the statutory trading prohibition. Accordingly, issuers may incur costs associated with assisting their directors and executive officers in determining whether transactions in equity securities of the issuer are exempt from the statutory trading prohibition and in identifying and tracking the equity securities that are subject to the trading prohibition. These costs are difficult to quantify, but are all imposed by the statute.

We believe that many U.S. issuers already maintain internal procedures for assisting their directors' and officers' compliance with the provisions of Section 16 of the Exchange Act and preventing violations of Section 10(b) of the Exchange Act and Exchange Act Rule 10b–5. It is likely that these issuers will enhance these internal procedures to address the trading prohibition of Section 306(a) and new Regulation BTR. Some issuers may need to institute appropriate internal procedures. Other issuers may need to modify existing procedures. Because the scope and sophistication of these internal procedures are likely to vary among issuers, it is difficult to provide an accurate estimate of the incremental cost of enhancing existing systems. Because we did not have data to quantify the cost of implementing, or upgrading and strengthening existing, internal insider trading procedures, we sought comments and supporting data on these costs. We did not receive any comments in response to our request.

Section 306(a) also imposes costs on directors and executive officers that are subject to Section 306(a)'s trading prohibition. Restrictions on trading activities increase the financial exposure to directors and executive officers during blackout periods and reduce their financial flexibility. This may result in losses in their portfolios or reduced profits. To some extent, these restrictions may tend to discourage some individuals from serving as directors or executive officers. They also could discourage some directors and executive officers from investing in the equity securities of the companies they serve or discourage some issuers from requiring minimum equity security ownership requirements (which could, in turn, disconnect the interests of directors and executive officers from those of security holders).

In addition, because many directors and executive officers of issuers that are subject to the reporting requirements of the Exchange Act are already subject to restrictions on their trading activities, such as the ''short-swing'' profits recovery provision of Section 16(b) of the Exchange Act, the introduction of an additional trading restriction to this existing framework may, in some instances, limit the ability of a director or executive officer to trade for significant periods. This also may result in losses in their portfolios or reduced profits. These costs are difficult to quantify, but may be mitigated somewhat by the timely notice required by Section 306(a).

V. Final Regulatory Flexibility Analysis

This Final Regulatory Flexibility Analysis, or FRFA, has been prepared in accordance with the Regulatory Flexibility Act.[175] The FRFA pertains to new rules that we are adopting to clarify the application of Section 306(a) of the Act and to prevent evasion of its statutory trading prohibition. The new rules also specify the content and timing of notice that issuers are required to

[174] We estimate that these burden hours will result in an aggregate cost of approximately $692,000 per year. This estimate is based on an estimated hourly rate of $100.00 to determine the estimated cost to issuers of having their employees handle the notice and filing requirements imposed by Section 306(a) of the Act and Regulation BTR. We arrived at this hourly rate estimate after consulting with several issuers and persons who assist issuers in filing reports with the Commission. We then multiplied this hourly rate by a factor of 1.35 to reflect appropriate overhead charges. 5,125 hours x $135.00 per hour = $691,875.

[175] 5 U.S.C. 603.

provide to their directors and executive officers and the Commission about the imposition of a pension plan blackout period.

A. Reasons for, and Objectives of, New Rules

Section 306(a) of the Act prohibits directors and executive officers of an issuer from purchasing, selling or otherwise acquiring or transferring any equity security of the issuer during a pension plan blackout period that prevents plan participants or beneficiaries from engaging in equity security transactions, if the equity security was acquired in connection with the director or executive officer's service or employment as a director or executive officer. In addition, Section 306(a) requires issuers to provide timely notice to their directors and executive officers and the Commission of the imposition of a blackout period. The new rules, which clarify the application of Section 306(a) and prevent evasion of its statutory trading prohibition, are intended to further the statute's purpose of mitigating the differential opportunities between an issuer's directors and executive officers and its employees who participate in pension plans maintained by the issuer at a time when a substantial number of those participants are unable to engage in transactions involving issuer equity securities through their individual pension plan accounts.

B. Significant Issues Raised by Public Comment

One commenter indicated that the compliance burden for small business issuers would not be disproportionate to the benefits to be obtained from compliance with Section 306(a) since concerns related to trading by corporate insiders are not unique to large issuers.[176]

C. Small Entities Subject to the New Rules

Section 306(a) of the Act affects, and the new rules affect, small entities the securities of which are registered under Section 12 of the Exchange Act, that are required to file reports under Section 15(d) of the Exchange Act or that file, or have filed, a registration statement that has not yet become effective under the Securities Act and that has not been withdrawn. For purposes of the Regulatory Flexibility Act, the Exchange Act[177] defines the term ''small business,'' other than an investment company, to be an issuer that, on the last day of its most recent fiscal year, has total assets of $5 million or less.[178] Section 306(a) and the new rules apply only to issuers with pension plans as defined in Section 3(34) of ERISA; we do not have data to indicate the number of small issuers that maintain such pension plans, but according to DOL data, only 30% of all issuers maintain such plans. Furthermore, our data indicates that temporary trading suspensions that will be subject to Section 306(a) occur to a plan approximately once every five years. If these percentages are accurate regardless of an issuer's size, the new rules should only affect approximately 150 small entities per year. We estimate that there are approximately 2,500 issuers that are subject to the Act that are not investment companies and that have assets of $5 million or less.[179] There are approximately 225 registered investment companies that may be considered small entities. However, as noted in the Proposing Release, we anticipate that the burden imposed on investment companies by Section 306(a) and the new rules will be negligible.

D. Reporting, Record Keeping and Other Compliance Requirements

Section 306(a) of the Act requires issuers, including ''small businesses,'' to provide timely notice to directors and executive officers and the Commission of a blackout period. The new rules specify the content and timing of this notice. The statute's basic prohibition against trading during blackout periods is largely self-executing and does not afford us with substantial discretion to exercise regulatory flexibility with respect to small businesses.

While a cost will be incurred in complying with the notice requirement, we believe that these costs will be minimal for small businesses. A required notice is likely to be prepared once for each blackout period and distributed to affected directors and executive officers. In addition, a current report on Form 8–K will be prepared and filed with the Commission. The cost of preparing and distributing the required notice to directors and executive officers is estimated to be approximately $590 annually per issuer for both large and small businesses.[180] The notice requirement involves a design standard in that the content of the notice to directors and executive officers and the form and content of the notice to the Commission is dictated by the new rules and will be comparable for all issuers, including small, as well as large, entities. We do not believe that excepting small businesses from making the notice is in the interests of their directors and executive officers, or consistent with Section 306(a).

While the new rules specify the content of the required notice to directors and executive officers, they do not dictate the specific form of the notice. In addition, the required notice to the Commission will be provided electronically through the filing of a current report on Form 8–K in the case of domestic issuers, or in an annual report on Form 20–F or 40–F in the case of foreign private issuers. We did not receive any information with respect to any special issues facing small businesses with respect to blackout period notices, or any alternatives consistent with the objectives of Section 306(a) of the Act that may serve to facilitate compliance by small businesses.

E. Duplicative, Overlapping or Conflicting Rules

We believe that there are no rules that duplicate, overlap or conflict with the new rules. We have intended the rules to coordinate with the rules adopted by the Department of Labor pursuant to Section 306(b) of the Sarbanes-Oxley Act of 2002. We also have coordinated the rules with the requirements under Section 16 of the Exchange Act for directors and officers to report transactions in their company's equity securities.

F. Agency Action To Minimize Effect on Small Entities

The Regulatory Flexibility Act directs us to consider significant alternatives that would accomplish the stated objectives, while minimizing any significant adverse impact on small entities. In that regard, we considered the following alternatives: (a) Establishing different compliance or reporting requirements that take into account the resources of small entities, (b) clarifying, consolidating or simplifying compliance and reporting requirements under the rules for small entities and (c) exempting small entities from all or part of the proposed rules. The new rules generally are intended to ensure that corporate insiders do not trade in an issuer's equity securities during periods when the ability of participants or beneficiaries in the issuer's pension plans to purchase, sell or otherwise acquire or transfer equity securities of the issuer has been

[176] *See* the Letter dated December 16, 2002 of PricewaterhouseCoopers LLP.

[177] 17 CFR 240.0–10(a).

[178] A similar definition is provided under Securities Act Rule 157 [17 CFR 230.157].

[179] This estimate is based on filings with the Commission.

[180] ($253,073 + (2,357 × $200 per hour))/1,230 blackouts = $589. *See* also Section IV.B above.

temporarily suspended. We do not currently believe that an exemption is necessary (since the cost of compliance is low) or appropriate (since Congress did not indicate that there should be different treatment for small businesses). While we solicited comment as to whether small business issuers should be excluded from the proposed rules, we did not receive any comments in response to our request. We also sought comment on the scope of the proposed disclosure, the cost of preparing it and whether the obligation can be simplified or clarified. We did not receive any comments in response to our request.

VI. Consideration of Burden on Competition

Section 23(a)(2) of the Exchange Act [181] requires us to consider the impact that any rule that we adopt will have on competition. In addition, Section 23(a)(2) prohibits us from adopting any rule that will impose a burden on competition not necessary or appropriate in furtherance of the purposes of the Exchange Act.

The new rules clarify the application and prevent evasion of Section 306(a) of the Act. Section 306(a) prohibits the directors and executive officers of an issuer from purchasing, selling or otherwise acquiring or transferring any equity security of the issuer during a pension plan blackout period that prevents plan participants or beneficiaries from engaging in issuer equity security transactions, if the equity security was acquired by the director or executive officer in connection with his or her service or employment as a director or executive officer. In addition, under Section 306(a) an issuer is required to provide timely notice to its directors and executive officers and the Commission of the imposition of a pension plan blackout period.

The new rules further the Section 306(a)'s purpose of mitigating the differential opportunities between an issuer's directors and executive officers and its employees who participate in pension plans maintained by the issuer at a time when a substantial number of these participants are unable to engage in transactions involving issuer equity securities through their individual pension plan accounts. The statute may have a slight impact on competition by placing restrictions on the ability of directors and executive officers of some issuers with pension plans to trade that are not placed on other issuers, although we believe it to be necessary and appropriate in furtherance of the purposes of the Act. Issuers will incur some costs in complying with the new rules. These costs will include preparing the required notice with the information specified in the new rules and providing notice to the Commission on a current report on Form 8–K or, in the case of a foreign private issuer, on Form 20–F or 40–F. We requested comment on whether the proposed rules, if adopted, would impose a burden on competition. We did not receive any comments in response to our request.

[181] 15 U.S.C. 78w(a)(2).

VII. Promotion of Efficiency, Competition and Capital Formation

Section 3(f) of the Exchange Act [182] requires us, when engaging in rulemaking where we are required to consider or determine whether an action is necessary or appropriate in the public interest, to consider, in addition to the protection of investors, whether the action will promote efficiency, competition and capital formation. The new rules clarify the application and prevent evasion of Section 306(a) of the Act. Section 306(a) prohibits directors and executive officers of an issuer from purchasing, selling or otherwise acquiring or transferring any equity security of the issuer during a pension plan blackout period that prevents plan participants or beneficiaries from engaging in issuer equity security transactions, if the equity security was acquired in connection with the director or executive officer's service or employment as a director or executive officer. In addition, Section 306(a) requires issuers to provide timely notice to their directors and executive officers and the Commission of the imposition of a pension plan blackout period.

The new rules further Section 306(a)'s purpose of mitigating the differential opportunities between an issuer's directors and executive officers and its employees who participate in pension plans maintained by the issuer at a time when a substantial number of these participants are unable to engage in transactions involving issuer equity securities through their individual pension plan accounts. The statute may have a slight impact on competition, including some burden on the efficiency of the market on an issuer's equity securities during a pension plan blackout period, although we believe it to be necessary and appropriate in furtherance of the purposes of the Act. The statute imposes this burden. We are not aware of any impact on capital formation that will result from the new rules. Issuers will incur some costs in complying with the new rules. These costs will include preparing the required notice to include the information specified in the new rules and providing notice to the Commission on a current report on Form 8–K or, in the case of a foreign private issuer, on Form 20–F or 40–F. We requested comment on whether the proposed rules, if adopted, would impose a burden on competition. We did not receive any comments in response to our request.

[182] 15 U.S.C. 78c(f).

VIII. Effective Date

The new rules are effective on January 26, 2003. The Administrative Procedure Act, or APA, generally requires that an agency publish an adopted rule in the **Federal Register** 30 days before it becomes effective.[183] This requirement, however, does not apply if the agency finds good cause for making the rule effective sooner.[184] The Commission believes that it is appropriate to waive advance publication of new Regulation BTR and the related rule and form amendments. Section 306(a) of the Act becomes effective on January 26, 2003. Congress has directed the Commission to clarify the operation of Section 306(a) by rule.[185] Our rules were coordinated with, and are dependent upon rules issued by the Department of Labor before January 26, 2003. It is impracticable to satisfy the advance publication requirement of the APA within the statutory deadline. It would be unnecessary and against the public interest to delay effectiveness of the new rules to satisfy this administrative requirement. Accordingly, the Commission finds good cause to make the new Regulation BTR, and the amendments to related rules and forms, effective on January 26, 2003.

IX. Statutory Authority

The rules contained in this release are being adopted under the authority set forth in Sections 3, 13, 23(a) and 36 of the Exchange Act, Sections 30 and 38 of the Investment Company Act and Sections 3(a) and 306(a) of the Sarbanes-Oxley Act of 2002.

List of Subjects in 17 CFR Parts 240, 245 and 249

Reporting and recordkeeping requirements, Securities.

Text of Final Rules and Forms

In accordance with the foregoing, Title 17, Chapter II, of the Code of

[183] *See* 5 U.S.C. 553(d).

[184] *Id.*

[185] *See* Section 306(a)(3) of the Act.

Federal Regulations is amended as follows:

PART 240—GENERAL RULES AND REGULATIONS, SECURITIES EXCHANGE ACT OF 1934

1. The authority citation for Part 240 is amended by adding the following citations in numerical order to read as follows:

Authority: 15 U.S.C. 77c, 77d, 77g, 77j, 77s, 77z–2, 77z–3, 77eee, 77ggg, 77nnn, 77sss, 77ttt, 78c, 78d, 78e, 78f, 78g, 78i, 78j, 78j–1, 78k, 78k–1, 78*l*, 78m, 78n, 78o, 78p, 78q, 78s, 78u–5, 78w, 78x, 78*ll*, 78mm, 79q, 79t, 80a–20, 80a–23, 80a–29, 80a–37, 80b–3, 80b–4 and 80b–11, unless otherwise noted.

* * * * *

Section 240.13a–11 is also issued under secs. 3(a) and 306(a), Pub. L. 107–204, 116 Stat. 745.

* * * * *

Section 240.15d–11 is also issued under secs. 3(a) and 306(a), Pub. L. 107–204, 116 Stat. 745.

* * * * *

2. Section § 240.13a–11 is amended by:

a. Removing the sectional authority following § 240.13a–11; and

b. Revising paragraph (b).

The revision reads as follows:

§ 240.13a–11 Current reports on Form 8–K (§ 249.308 of this chapter).

* * * * *

(b) This section shall not apply to foreign governments, foreign private issuers required to make reports on Form 6–K (17 CFR 249.306) pursuant to § 240.13a–16, issuers of American Depositary Receipts for securities of any foreign issuer, or investment companies required to file reports pursuant to § 270.30b1–1 of this chapter under the Investment Company Act of 1940, except where such investment companies are required to file notice of a blackout period pursuant to § 245.104 of this chapter.

3. Section § 240.15d–11 is amended by:

a. Removing the sectional authority following § 240.15d–11; and

b. Revising paragraph (b).

The revision reads as follows:

§ 240.15d–11 Current reports on Form 8–K (§ 249.308 of this chapter).

* * * * *

(b) This section shall not apply to foreign governments, foreign private issuers required to make reports on Form 6–K (17 CFR 249.306) pursuant to § 240.15d–16, issuers of American Depositary Receipts for securities of any foreign issuer, or investment companies required to file periodic reports pursuant to § 270.30b1–1 of this chapter under the Investment Company Act of 1940, except where such investment companies are required to file notice of a blackout period pursuant to § 245.104 of this chapter.

4. Part 245 is added to read as follows:

PART 245—REGULATION BLACKOUT TRADING RESTRICTION

[Regulation BTR—Blackout Trading Restriction]

Sec.
245.100 Definitions.
245.101 Prohibition of insider trading during pension fund blackout periods.
245.102 Exceptions to definition of blackout period.
245.103 Issuer right of recovery; right of action by equity security owner.
245.104 Notice.

Authority: 15 U.S.C. 78w(a), unless otherwise noted.

Sections 245.100–245.104 are also issued under secs. 3(a) and 306(a), Pub. L. 107–204, 116 Stat. 745.

§ 245.100 Definitions.

As used in Regulation BTR (§§ 245.100 through 245.104), unless the context otherwise requires:

(a) The term *acquired in connection with service or employment as a director or executive officer*, when applied to a director or executive officer, means that he or she acquired, directly or indirectly, an equity security:

(1) At a time when he or she was a director or executive officer, under a compensatory plan, contract, authorization or arrangement, including, but not limited to, an option, warrants or rights plan, a pension, retirement or deferred compensation plan or a bonus, incentive or profit-sharing plan (whether or not set forth in any formal plan document), including a compensatory plan, contract, authorization or arrangement with a parent, subsidiary or affiliate;

(2) At a time when he or she was a director or executive officer, as a result of any transaction or business relationship described in paragraph (a) or (b) of Item 404 of Regulation S–K (§ 229.404 of this chapter) or, in the case of a foreign private issuer, Item 7.B of Form 20–F (§ 249.220f of this chapter) (but without application of the disclosure thresholds of such provisions), to the extent that he or she has a pecuniary interest (as defined in paragraph (*l*) of this section) in the equity securities;

(3) At a time when he or she was a director or executive officer, as directors' qualifying shares or other securities that he or she must hold to satisfy minimum ownership requirements or guidelines for directors or executive officers;

(4) Prior to becoming, or while, a director or executive officer where the equity security was acquired as a direct or indirect inducement to service or employment as a director or executive officer; or

(5) Prior to becoming, or while, a director or executive officer where the equity security was received as a result of a business combination in respect of an equity security of an entity involved in the business combination that he or she had acquired in connection with service or employment as a director or executive officer of such entity.

(b) Except as provided in § 245.102, the term *blackout period*:

(1) With respect to the equity securities of any issuer (other than a foreign private issuer), means any period of more than three consecutive business days during which the ability to purchase, sell or otherwise acquire or transfer an interest in any equity security of such issuer held in an individual account plan is temporarily suspended by the issuer or by a fiduciary of the plan with respect to not fewer than 50% of the participants or beneficiaries located in the United States and its territories and possessions under all individual account plans (as defined in paragraph (j) of this section) maintained by the issuer that permit participants or beneficiaries to acquire or hold equity securities of the issuer;

(2) With respect to the equity securities of any foreign private issuer (as defined in § 240.3b–4(c) of this chapter), means any period of more than three consecutive business days during which both:

(i) The conditions of paragraph (b)(1) of this section are met; and

(ii)(A) The number of participants and beneficiaries located in the United States and its territories and possessions subject to the temporary suspension exceeds 15% of the total number of employees of the issuer and its consolidated subsidiaries; or

(B) More than 50,000 participants and beneficiaries located in the United States and its territories and possessions are subject to the temporary suspension.

(3) In determining the individual account plans (as defined in paragraph (j) of this section) maintained by an issuer for purposes of this paragraph (b):

(i) The rules under section 414(b), (c), (m) and (o) of the Internal Revenue Code (26 U.S.C. 414(b), (c), (m) and (o)) are to be applied; and

(ii) An individual account plan that is maintained outside of the United States primarily for the benefit of persons substantially all of whom are

nonresident aliens (within the meaning of section 104(b)(4) of the Employee Retirement Income Security Act of 1974 (29 U.S.C. 1003(b)(4))) is not to be considered.

(4) In determining the number of participants and beneficiaries in an individual account plan (as defined in paragraph (j) of this section) maintained by an issuer:

(i) The determination may be made as of any date within the 12-month period preceding the beginning date of the temporary suspension in question; provided that if there has been a significant change in the number of participants or beneficiaries in an individual account plan since the date selected, the determination for such plan must be made as of the most recent practicable date that reflects such change; and

(ii) The determination may be made without regard to overlapping plan participation.

(c)(1) The term *director* has, except as provided in paragraph (c)(2) of this section, the meaning set forth in section 3(a)(7) of the Exchange Act (15 U.S.C. 78c(a)(7)).

(2) In the case of a foreign private issuer (as defined in § 240.3b–4(c) of this chapter), the term *director* means an individual within the definition set forth in section 3(a)(7) of the Exchange Act who is a management employee of the issuer.

(d) The term *derivative security* has the meaning set forth in § 240.16a–1(c) of this chapter.

(e) The term *equity security* has the meaning set forth in section 3(a)(11) of the Exchange Act (15 U.S.C. 78c(a)(11)) and § 240.3a11–1 of this chapter.

(f) The term *equity security of the issuer* means any equity security or derivative security relating to an issuer, whether or not issued by that issuer.

(g) The term *Exchange Act* means the Securities Exchange Act of 1934 (15 U.S.C. 78a *et seq.*).

(h)(1) The term *executive officer* has, except as provided in paragraph (h)(2) of this section, the meaning set forth in § 240.16a–1(f) of this chapter.

(2) In the case of a foreign private issuer (as defined in § 240.3b–4(c) of this chapter), the term *executive officer* means the principal executive officer or officers, the principal financial officer or officers and the principal accounting officer or officers of the issuer.

(i) The term *exempt security* has the meaning set forth in section 3(a)(12) of the Exchange Act (15 U.S.C. 78c(a)(12)).

(j) The term *individual account plan* means a pension plan which provides for an individual account for each participant and for benefits based solely upon the amount contributed to the participant's account, and any income, expenses, gains and losses, and any forfeitures of accounts of other participants which may be allocated to such participant's account, except that such term does not include a one-participant retirement plan (within the meaning of section 101(i)(8)(B) of the Employee Retirement Income Security Act of 1974 (29 U.S.C. 1021(i)(8)(B))), nor does it include a pension plan in which participation is limited to directors of the issuer.

(k) The term *issuer* means an issuer (as defined in section 3(a)(8) of the Exchange Act (15 U.S.C. 78c(a)(8))), the securities of which are registered under section 12 of the Exchange Act (15 U.S.C. 78*l*) or that is required to file reports under section 15(d) of the Exchange Act (15 U.S.C. 78o(d)) or that files or has filed a registration statement that has not yet become effective under the Securities Act of 1933 (15 U.S.C. 77a *et seq.*) and that it has not withdrawn.

(l) The term *pecuniary interest* has the meaning set forth in § 240.16a–1(a)(2)(i) of this chapter and the term *indirect pecuniary interest* has the meaning set forth in § 240.16a–1(a)(2)(ii) of this chapter. Section 240.16a–1(a)(2)(iii) of this chapter also shall apply to determine pecuniary interest for purposes of this regulation.

§ 245.101 Prohibition of insider trading during pension fund blackout periods.

(a) Except to the extent otherwise provided in paragraph (c) of this section, it is unlawful under section 306(a)(1) of the Sarbanes-Oxley Act of 2002 (15 U.S.C. 7244(a)(1)) for any director or executive officer of an issuer of any equity security (other than an exempt security), directly or indirectly, to purchase, sell or otherwise acquire or transfer any equity security of the issuer (other than an exempt security) during any blackout period with respect to such equity security, if such director or executive officer acquires or previously acquired such equity security in connection with his or her service or employment as a director or executive officer.

(b) For purposes of section 306(a)(1) of the Sarbanes-Oxley Act of 2002, any sale or other transfer of an equity security of the issuer during a blackout period will be treated as a transaction involving an equity security ''acquired in connection with service or employment as a director or executive officer'' (as defined in § 245.100(a)) to the extent that the director or executive officer has a pecuniary interest (as defined in § 245.100(l)) in such equity security, unless the director or executive officer establishes by specific identification of securities that the transaction did not involve an equity security ''acquired in connection with service or employment as a director or executive officer.'' To establish that the equity security was not so acquired, a director or executive officer must identify the source of the equity securities and demonstrate that he or she has utilized the same specific identification for any purpose related to the transaction (such as tax reporting and any applicable disclosure and reporting requirements).

(c) The following transactions are exempt from section 306(a)(1) of the Sarbanes-Oxley Act of 2002:

(1) Any acquisition of equity securities resulting from the reinvestment of dividends in, or interest on, equity securities of the same issuer if the acquisition is made pursuant to a plan providing for the regular reinvestment of dividends or interest and the plan provides for broad-based participation, does not discriminate in favor of employees of the issuer and operates on substantially the same terms for all plan participants;

(2) Any purchase or sale of equity securities of the issuer pursuant to a contract, instruction or written plan entered into by the director or executive officer that satisfies the affirmative defense conditions of § 240.10b5–1(c) of this chapter; provided that the director or executive officer did not enter into or modify the contract, instruction or written plan during the blackout period (as defined in § 245.100(b)) in question, or while aware of the actual or approximate beginning or ending dates of that blackout period (whether or not the director or executive officer received notice of the blackout period as required by Section 306(a)(6) of the Sarbanes-Oxley Act of 2002 (15 U.S.C. 7244(a)(6))).

(3) Any purchase or sale of equity securities, other than a Discretionary Transaction (as defined in § 240.16b–3(b)(1) of this chapter), pursuant to a Qualified Plan (as defined in § 240.16b–3(b)(4) of this chapter), an Excess Benefit Plan (as defined in § 240.16b–3(b)(2) of this chapter) or a Stock Purchase Plan (as defined in § 240.16b–3(b)(5) of this chapter) (or, in the case of a foreign private issuer, pursuant to an employee benefit plan that either (i) has been approved by the taxing authority of a foreign jurisdiction, or (ii) is eligible for preferential treatment under the tax laws of a foreign jurisdiction because the plan provides for broad-based employee participation); provided that a Discretionary Transaction that meets the conditions of

paragraph (c)(2) of this section also shall be exempt;

(4) Any grant or award of an option, stock appreciation right or other equity compensation pursuant to a plan that, by its terms:

(i) Permits directors or executive officers to receive grants or awards; and

(ii) Either:

(A) States the amount and price of securities to be awarded to designated directors and executive officers or categories of directors and executive officers (though not necessarily to others who may participate in the plan) and specifies the timing of awards to directors and executive officers; or

(B) Sets forth a formula that determines the amount, price and timing, using objective criteria (such as earnings of the issuer, value of the securities, years of service, job classification, and compensation levels);

(5) Any exercise, conversion or termination of a derivative security that the director or executive officer did not write or acquire during the blackout period (as defined in § 245.100(b)) in question, or while aware of the actual or approximate beginning or ending dates of that blackout period (whether or not the director or executive officer received notice of the blackout period as required by Section 306(a)(6) of the Sarbanes-Oxley Act of 2002); and either:

(i) The derivative security, by its terms, may be exercised, converted or terminated only on a fixed date, with no discretionary provision for earlier exercise, conversion or termination; or

(ii) The derivative security is exercised, converted or terminated by a counterparty and the director or executive officer does not exercise any influence on the counterparty with respect to whether or when to exercise, convert or terminate the derivative security;

(6) Any acquisition or disposition of equity securities involving a bona fide gift or a transfer by will or the laws of descent and distribution;

(7) Any acquisition or disposition of equity securities pursuant to a domestic relations order, as defined in the Internal Revenue Code or Title I of the Employment Retirement Income Security Act of 1974, or the rules thereunder;

(8) Any sale or other disposition of equity securities compelled by the laws or other requirements of an applicable jurisdiction;

(9) Any acquisition or disposition of equity securities in connection with a merger, acquisition, divestiture or similar transaction occurring by operation of law; and

(10) The increase or decrease in the number of equity securities held as a result of a stock split or stock dividend applying equally to all securities of that class, including a stock dividend in which equity securities of a different issuer are distributed; and the acquisition of rights, such as shareholder or pre-emptive rights, pursuant to a pro rata grant to all holders of the same class of equity securities.

§ 245.102 Exceptions to definition of blackout period.

The term ''blackout period,'' as defined in § 245.100(b), does not include:

(a) A regularly scheduled period in which participants and beneficiaries may not purchase, sell or otherwise acquire or transfer an interest in any equity security of an issuer, if a description of such period, including its frequency and duration and the plan transactions to be suspended or otherwise affected, is:

(1) Incorporated into the individual account plan or included in the documents or instruments under which the plan operates; and

(2) Disclosed to an employee before he or she formally enrolls, or within 30 days following formal enrollment, as a participant under the individual account plan or within 30 days after the adoption of an amendment to the plan. For purposes of this paragraph (a)(2), the disclosure may be provided in any graphic form that is reasonably accessible to the employee; or

(b) Any trading suspension described in § 245.100(b) that is imposed in connection with a corporate merger, acquisition, divestiture or similar transaction involving the plan or plan sponsor, the principal purpose of which is to permit persons affiliated with the acquired or divested entity to become participants or beneficiaries, or to cease to be participants or beneficiaries, in an individual account plan; provided that the persons who become participants or beneficiaries in an individual account plan are not able to participate in the same class of equity securities after the merger, acquisition, divestiture or similar transaction as before the transaction.

§ 245.103 Issuer right of recovery; right of action by equity security owner.

(a) *Recovery of profits.* Section 306(a)(2) of the Sarbanes-Oxley Act of 2002 (15 U.S.C. 7244(a)(2)) provides that any profit realized by a director or executive officer from any purchase, sale or other acquisition or transfer of any equity security of an issuer in violation of section 306(a)(1) of that Act (15 U.S.C. 7244(a)(1)) will inure to and be recoverable by the issuer, regardless of any intention on the part of the director or executive officer in entering into the transaction.

(b) *Actions to recover profit.* Section 306(a)(2) of the Sarbanes-Oxley Act of 2002 provides that an action to recover profit may be instituted at law or in equity in any court of competent jurisdiction by the issuer, or by the owner of any equity security of the issuer in the name and on behalf of the issuer if the issuer fails or refuses to bring such action within 60 days after the date of request, or fails diligently to prosecute the action thereafter, except that no such suit may be brought more than two years after the date on which such profit was realized.

(c) *Measurement of profit.*

(1) In determining the profit recoverable in an action undertaken pursuant to section 306(a)(2) of the Sarbanes-Oxley Act of 2002 from a transaction that involves a purchase, sale or other acquisition or transfer (other than a grant, exercise, conversion or termination of a derivative security) in violation of section 306(a)(1) of that Act of an equity security of an issuer that is registered pursuant to section 12(b) or 12(g) of the Exchange Act (15 U.S.C. 78*l*(b) or (g)) and listed on a national securities exchange or listed in an automated inter-dealer quotation system of a national securities association, profit (including any loss avoided) may be measured by comparing the difference between the amount paid or received for the equity security on the date of the transaction during the blackout period and the average market price of the equity security calculated over the first three trading days after the ending date of the blackout period.

(2) In determining the profit recoverable in an action undertaken pursuant to section 306(a)(2) of the Sarbanes-Oxley Act of 2002 from a transaction that is not described in paragraph (c)(1) of this section, profit (including any loss avoided) may be measured in a manner that is consistent with the objective of identifying the amount of any gain realized or loss avoided by a director or executive officer as a result of a transaction taking place in violation of section 306(a)(1) of that Act during the blackout period as opposed to taking place outside of such blackout period.

(3) The terms of this section do not limit in any respect the authority of the Commission to seek or determine remedies as the result of a transaction

taking place in violation of section 306(a)(1) of the Sarbanes-Oxley Act.

§ 245.104 Notice.

(a) In any case in which a director or executive officer is subject to section 306(a)(1) of the Sarbanes-Oxley Act of 2002 (15 U.S.C. 7244(a)(1)) in connection with a blackout period (as defined in § 245.100(b)) with respect to any equity security, the issuer of the equity security must timely notify each director or officer and the Commission of the blackout period.

(b) For purposes of this section:

(1)The notice must include:

(i) The reason or reasons for the blackout period;

(ii) A description of the plan transactions to be suspended during, or otherwise affected by, the blackout period;

(iii) A description of the class of equity securities subject to the blackout period;

(iv) The length of the blackout period by reference to:

(A) The actual or expected beginning date and ending date of the blackout period; or

(B) The calendar week during which the blackout period is expected to begin and the calendar week during which the blackout period is expected to end, provided that the notice to directors and executive officers describes how, during such week or weeks, a director or executive officer may obtain, without charge, information as to whether the blackout period has begun or ended; and provided further that the notice to the Commission describes how, during the blackout period and for a period of two years after the ending date of the blackout period, a security holder or other interested person may obtain, without charge, the actual beginning and ending dates of the blackout period.

(C) For purposes of this paragraph (b)(1)(iv), a *calendar week* means a seven-day period beginning on Sunday and ending on Saturday; and

(v) The name, address and telephone number of the person designated by the issuer to respond to inquiries about the blackout period, or, in the absence of such a designation, the issuer's human resources director or person performing equivalent functions.

(2) (i) Notice to an affected director or executive officer will be considered timely if the notice described in paragraph (b)(1) of this section is provided (in graphic form that is reasonably accessible to the recipient):

(A) No later than five business days after the issuer receives the notice required by section 101(i)(2)(E) of the Employment Retirement Income Security Act of 1974 (29 U.S.C. 1021(i)(2)(E)); or

(B) If no such notice is received by the issuer, a date that is at least 15 calendar days before the actual or expected beginning date of the blackout period.

(ii) Notwithstanding paragraph (b)(2)(i) of this section, the requirement to give advance notice will not apply in any case in which the inability to provide advance notice of the blackout period is due to events that were unforeseeable to, or circumstances that were beyond the reasonable control of, the issuer, and the issuer reasonably so determines in writing. Determinations described in the preceding sentence must be dated and signed by an authorized representative of the issuer. In any case in which this exception to the advance notice requirement applies, the issuer must provide the notice described in paragraph (b)(1) of this section, as well as a copy of the written determination, to all affected directors and executive officers as soon as reasonably practicable.

(iii) If there is a subsequent change in the beginning or ending dates of the blackout period as provided in the notice to directors and executive officers under paragraph (b)(2)(i) of this section, an issuer must provide directors and executive officers with an updated notice explaining the reasons for the change in the date or dates and identifying all material changes in the information contained in the prior notice. The updated notice is required to be provided as soon as reasonably practicable, unless such notice in advance of the termination of a blackout period is impracticable.

(3) Notice to the Commission will be considered timely if:

(i) The issuer, except as provided in paragraph (b)(3)(ii) of this section, files a current report on Form 8–K (§ 249.308 of this chapter) within the time prescribed for filing the report under the instructions for the form; or

(ii) In the case of a foreign private issuer (as defined in § 240.3b–4(c) of this chapter), the issuer includes the information set forth in paragraph (b)(1) of this section in the first annual report on Form 20–F (§ 249.220f of this chapter) or 40–F (§ 249.240f of this chapter) required to be filed after the receipt of the notice of a blackout period required by 29 CFR 2520.101–3(c) within the time prescribed for filing the report under the instructions for the form or in an earlier filed report on Form 6–K (§ 249.306).

(iii) If there is a subsequent change in the beginning or ending dates of the blackout period as provided in the notice to the Commission under paragraph (b)(3)(i) of this section, an issuer must file a current report on Form 8–K containing the updated beginning or ending dates of the blackout period, explaining the reasons for the change in the date or dates and identifying all material changes in the information contained in the prior report. The updated notice is required to be provided as soon as reasonably practicable.

PART 249—FORMS, SECURITIES EXCHANGE ACT OF 1934

5. The authority citation for Part 249 is amended by revising the sectional authority for § 249.308 to read as follows:

Authority: 15 U.S.C. 78a, *et seq.*, unless otherwise noted.

* * * * *

Section 249.308 is also issued under 15 U.S.C. 80a–29, 80a–37 and secs. 3(a), 302 and 306(a), Pub. L. 107–204, 116 Stat. 745.

* * * * *

6. Form 20–F (referenced in § 249.220f) is amended by:

a. Redesignating paragraph (10) as paragraph (11) under ''Instructions as to Exhibits'; and

b. Adding paragraph (10) under ''Instructions as to Exhibits.''

The addition reads as follows:

Note: The text of Form 20–F does not, and this amendment will not, appear in the Code of Federal Regulations.

Form 20–F

* * * * *

Instructions As To Exhibits

* * * * *

10. Any notice required by Rule 104 of Regulation BTR (17 CFR 245.104 of this chapter) that you sent during the past fiscal year to directors and executive officers (as defined in 17 CFR 245.100(d) and (h) of this chapter) concerning any equity security subject to a blackout period (as defined in 17 CFR 245.100(c) of this chapter) under Rule 101 of Regulation BTR (17 CFR 245.101 of this chapter). Each notice must have included the information specified in 17 CFR 245.104(b) of this chapter.

Note: The exhibit requirement in paragraph (10) applies only to an annual report, and not to a registration statement, on Form 20–F. The Commission will consider the attachment of any Rule 104 notice as an exhibit to a timely filed Form 20–F annual report to satisfy an issuer's duty to notify the Commission of a blackout period in a timely manner. Although an issuer need not submit a Rule 104 notice under cover of a Form 6–K, if an issuer has already submitted this notice under cover of Form 6–K, it need not

attach the notice as an exhibit to a Form 20–F annual report.

* * * * *

7. Form 40–F (referenced in § 249.240f) is amended by adding new paragraph (7) to General Instruction B to read as follows:

Note: The text of Form 40–F does not, and this amendment will not, appear in the Code of Federal Regulations.

Form 40–F

* * * * *

General Instructions

* * * * *

B. Information To Be Filed on This Form

* * * * *

(7) An issuer must attach as an exhibit to an annual report filed on Form 40–F a copy of any notice required by Rule 104 of Regulation BTR (17 CFR 245.104 of this chapter) that it sent during the past fiscal year to directors and executive officers (as defined in 17 CFR 245.100(d) and (h) of this chapter) concerning any equity security subject to a blackout period (as defined in 17 CFR 245.100(c) of this chapter) under Rule 101 of Regulation BTR (17 CFR 245.101 of this chapter). Each notice must have included the information specified in 17 CFR 245.104(b) of this chapter.

Note: The Commission will consider the attachment of any Rule 104 notice as an exhibit to a timely filed Form 40–F annual report to satisfy an issuer's duty to notify the Commission of a blackout period in a timely manner. Although an issuer need not submit a Rule 104 notice under cover of a Form 6–K, if an issuer has already submitted this notice under cover of Form 6–K, it need not attach the notice as an exhibit to a Form 40–F annual report.

* * * * *

8. Form 8–K (referenced in § 249.308) is amended by:

a. Revising General Instruction 1; and

b. Adding Item 11 under ''Information to be Included in the Report.''

The revision and addition read as follows:

Note: The text of Form 8–K does not, and this amendment will not, appear in the Code of Federal Regulations.

Form 8–K

* * * * *

General Instructions

* * * * *

B. Events To Be Reported and Time for Filing of Reports

1. * * * A report on this form pursuant to Item 11 is required to be filed not later than the date prescribed for transmission of the notice to directors and executive officers required by Rule 104(b)(2) of Regulation BTR (§ 245.104(b)(2) of this chapter).

* * * * *

Information to be Included in the Report

* * * * *

Item 11. Temporary Suspension of Trading Under Registrant's Employee Benefit Plans

Not later than the date prescribed for transmission of the notice required by Rule 104(b)(2) of Regulation BTR (§ 245.104(b)(2) of this chapter), provide the information specified in § 245.104(b) of this chapter and the date the registrant received the notice required by section 101(i)(2)(E) of the Employment Retirement Income Security Act of 1974 (29 U.S.C. 1021(i)(2)(E)).

* * * * *

Dated: January 22, 2003.

By the Commission.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 03–1884 Filed 1–27–03; 8:45 am]

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REMINDERS

The items in this list were editorially compiled as an aid to Federal Register users. Inclusion or exclusion from this list has no legal significance.

RULES GOING INTO EFFECT JANUARY 28, 2003

COMMERCE DEPARTMENT

National Oceanic and Atmospheric Administration

Fishery conservation and management:

Northeastern United States fisheries—

Northeast multispecies; published 1-28-03

FEDERAL COMMUNICATIONS COMMISSION

Freedom of Information Act; implementation; published 1-28-03

Radio stations; table of assignments:

Texas; published 1-28-03

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Merchant marine officers and seamen:

Passenger ships on international voyages; personnel training and qualifications; published 10-30-02

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Airworthiness directives:

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Animal and Plant Health Inspection Service

Exportation and importation of animals and animal products:

Horse importation quarantine facilities; stall reservations; comments due by 2-7-03; published 12-9-02 [FR 02-31009]

AGRICULTURE DEPARTMENT

Food Safety and Inspection Service

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Food labeling—

Nutrient content claims; definition of term healthy; comments due by 2-5-03; published 1-6-03 [FR 02-33150]

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National Oceanic and Atmospheric Administration

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National Oceanic and Atmospheric Administration

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National Oceanic and Atmospheric Administration

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National Oceanic and Atmospheric Administration

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ENVIRONMENTAL PROTECTION AGENCY

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Air programs; approval and promulgation; State plans for designated facilities and pollutants:

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ENVIRONMENTAL PROTECTION AGENCY

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TRANSPORTATION DEPARTMENT

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LIST OF PUBLIC LAWS

This is a continuing list of public bills from the current session of Congress which have become Federal laws. It may be used in conjunction with ''P L U S'' (Public Laws Update Service) on 202–741–6043. This list is also available online at *http://www.nara.gov/fedreg/plawcurr.html*.

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H.R. 11/P.L. 108–3

National Flood Insurance Program Reauthorization Act of 2003 (Jan. 13, 2003; 117 Stat. 7)

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